LOAD FORECAST

Economics &
Forecasts Division
Corporate Planning Branch

No. 891211

LOAD FORECASTS REPORT

NO. 891211

SYSTEM DEMANDS

Load Forecasts Department
Economics and Forecasts Division
Corporate Planning Branch

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TABLE OF CONTENTS

		Page
INTRODUCTION		i
1.0	THE SHORT-TERM LOAD FORECAST - 1989 TO 1994	1
1.1	Highlights	1
1.1.1	The Short-Term Primary Load Forecast	1
1.1.2	Comparison with Load Forecast 881212 - Peak Demand	2
1.1.3	Comparison with Load Forecast 881212 - Energy Demand	4
1.1.4	Derivation of the Primary Load Forecast from the Basic Load Forecast	5
1.2	Inputs to the Forecast	7
1.2.1	Regional Estimates	7
1.2.2	Economic Conditions and Trends	8
1.2.3	Short-Term Forecasting Models	9
1.3	Determining the Basic Load Forecast and the Unallocated Load	10
1.3.1	Weather	12
1.3.2	Losses	12
1.3.3.	Capacity Interruptible Loads	12
1.4	Performance of Load Forecast 881212 in 1989	13
1.4.1	Actual Primary Demand Versus Forecast 881212	13
1.4.2	Weather-Corrected Primary Demand Versus Forecast 881212	15
2.0	THE LONG-TERM PRIMARY LOAD FORECAST - 1995 TO 2015	16
2.1	Highlights	16
2.1.1	Load Forecast 891211	17
2.1.2	Comparison with Load Forecast 881212 - Primary Energy Demand	17
2.1.3	Comparison with Load Forecast 881212 - Primary Peak Demand	18
2.1.4	Comparison of Primary to Basic Load Forecast	19
2.1.5	Comparison of Basic Load Forecast 891211 with Basic Load Forecast 881212	20
2.1.6	Comparison of Net Load Impacts of Demand Management and Load Displacement Programs, LF891211 versus LF881212	21
2.1.7	Selection of Recommended Primary Load Forecast	22
2.2	Load Forecast Uncertainty	23
2.3	Alternative Scenarios	25
3.0	THE LONG-TERM BASIC LOAD FORECAST - METHODOLOGY AND ASSUMPTIONS	27
3.1	Methodology	27
3.2	Discussion of Major Assumptions	28
3.2.1	Economic Trends	28
3.2.2	Energy Prices	29
3.3	Risks to the Forecast	30

TABLE OF CONTENTS (Continued)

		Page
4.0	**THE LONG-TERM BASIC LOAD FORECAST-RESULTS OF THE FORECASTING MODELS**	**32**
4.1	End-Use Models Forecast	32
4.1.1	Residential Sector	33
4.1.2	Commercial Sector	39
4.1.3	Industrial Sector	46
4.1.4	Transportation Sector	53
4.1.5	Agricultural Sector	54
4.1.6	The 1989 End-Use Forecast	54
4.2	Econometric Energy Model of Ontario - EEMO	56
4.2.1	Residential Sector	56
4.2.2	Industrial Sector	58
4.2.3	Commercial Sector	60
4.2.4	The 1989 EEMO Forecast	61
5.0	**LOAD IMPACT OF INCENTIVE-DRIVEN DEMAND MANAGEMENT AND LOAD DISPLACEMENT**	**63**
5.1	Introduction	63
5.2	Incentive-Driven Demand Management	63
5.2.1	Electrical Efficiency Improvement Programs	64
5.2.1.1	Program Description by Sector	64
5.2.1.2	The Forecast of Net Load Impact by Sector	67
5.2.2	Load-Shifting Programs	70
5.2.2.1	Program Description	70
5.2.2.2	Forecast of Impact of Load-Shifting Programs	71
5.2.3	Forecast of the Net Load Impact of Demand Management Programs	73
5.3	Load Displacement Non-Utility Generation Forecast	77
6.0	**PERFORMANCE OF LOAD FORECAST 891211 in 1989**	**102**
6.1	Actual Primary Demand Versus Forecast	102
6.2	Weather-Corrected Primary Demand Versus Forecast	102
6.3	Diversity and Losses	103
6.4	Unallocated Load	104
6.5	Detail of Customer Loads	104
7.0	**UNCERTAINTY IN THE LOAD FORECAST**	**107**
7.1	Introduction	107
7.2	The Estimated Equations	107
7.3	Estimated 80% Confidence Interval for Annual System Energy	107
7.4	Refinements to the 1988 Methodology included in the 1989 Load Forecast	108

TABLE OF CONTENTS (Continued)

		Page
8.0	GLOSSARY	111
8.1	Demand (Versus Load)	111
8.1.1	Basic Load Forecast	113
8.1.2	Primary Load Forecast	113
8.2	Diversity and Losses	113
8.3	Customers' Loads	113
8.3.1	Firm Loads	114
8.3.2	Capacity Interruptible Loads	114
8.4	Standby Power	114

INTRODUCTION

The Load Forecasts Department normally issues two load forecasts each year: a Long-Term Forecast, produced in the fall for system planning purposes; and a Short-Term Forecast, produced in early summer for revenue planning, rate development and budget purposes. The Long-Term Forecast has a time horizon of approximately 25 years.

This Load Forecast Report contains the Short-Term and Long-Term Load Forecasts approved by the Board of Directors on December 11, 1989.

The Short-Term Load Forecast for the period 1989-1994 is presented first. It was prepared using the results of:

- A customer survey carried out in the spring (called Regional Estimates);
- The updated economic forecasts based on the latest trends and anticipated changes in the economic environment;
- Electricity demand forecast models relying on the most recent data;
- The latest analysis of the deviations of recent Ontario electricity demands from last year's predictions;
- A forecast of the Net Load Impact of Program-Driven Demand Management and Load Displacement Generation.

The Short-Term Primary Load Forecast section includes a comparison of the Primary Load Forecast with last year's Primary Load Forecast and this year's Basic Load Forecast, a discussion of the Net Impact of Program Driven Demand Management and Load Displacement Generation, and a summary of the Regional Estimates. Also provided is a brief commentary on considerations affecting the forecast, such as the economic outlook, future electricity price levels, weather effects, and the amount of electricity attributed to unallocated load and transmission losses. With the exception of unallocated load, all these factors contribute to the uncertainty associated with the forecast. The uncertainty with respect to the Short-Term Forecast is covered along with the Long-Term Forecast in Section 2.1.5. Analysis of the performance of last year's forecast, a description of the short-term forecasting models we use and the forecast of capacity interruptible loads complete the section on the short-term forecast.

The Long-Term Load Forecast for the years 1995-2015 was derived taking into account several inputs: the short-term forecast, the long-term economic outlook, econometric model (EEMO) estimates, end-use model estimates, the 1988 Load Forecast, judgmental factors, and the forecast of the net load impact of program-driven Demand Management and Load Displacement Generation.

The presentation of the Long-Term Primary Load Forecast is similar to that for the Short-Term. The chapter includes the results of two different approaches to forecasting, the econometric (EEMO) and end-use models, as well as two approaches to describing Basic Load Forecast uncertainty using statistical confidence interval or alternative load growth scenarios generated by the EEMO model derived from alternative macroeconomic scenarios.

Since 1986, an amount has been subtracted from the Short- and Long-Term Basic Load Forecasts to show the forecasted effects of the net load impact of program-driven Demand Management and Load Displacement Generation on total system demand. The resulting forecast is the Primary Load Forecast. All notation and tables presented in his report refer to the Primary Load Forecast unless the Basic Load Forecast is explicitly noted. The Primary Load Forecast has the same role in the planning process as it always has: it is the most-likely projection of the load Ontario Hydro must plan to supply (after directly controlled loads have been netted out).

The forecast of the Net Load Impact of Program-Driven Demand Management is the estimated net impact on the Basic Load Forecast of programs initiated by Ontario Hydro to alter the level and the shape of the load. The Net Impact of Program-Driven Load Displacement Non-utility Generation forecast is the expected reduction in Primary Load due to program-induced additional self-generation of electricity by Ontario Hydro's customers above and beyond that which would otherwise have occurred. It is projected that these demand management strategies together will reduce energy demand by 21.7 TW.h in the year 2015, resulting in a Primary Load Forecast of 232.9 TW.h, compared with the Basic level of 254.6 TW.h.

Supplementary reports have been prepared which provide additional detail: individual customers' monthly energy for the period 1989-1994 and an aggregation of load for all customer classes within areas, projected to the year 2015. These reports are not printed for wide distribution because they are of limited interest to most readers. They are available in machine-readable form for users who require the data. In the past, tables for monthly customer load and primary demand for the East, West and Total Systems were provided in this report. These are no longer included, but can be obtained upon request.

1.0 THE SHORT-TERM LOAD FORECAST - 1989 TO 1994

1.1 Highlights

The 1989 Short-Term Load Forecast is higher than the December 1988 Short Term Load Forecast in all forecast years. The average annual rate of growth for primary energy between 1989 and 1994 is 2.6% which is the same growth rate as last year, but applied to a base which is 1.7% higher by the end of 1989. By 1994, primary load is forecast to be 158 TW.h, 3 TW.h higher than last year. The average absolute increase in load over this period is 4.0 TW.h per year.

The Primary Load Forecast is derived from the Basic Load Forecast by subtracting the estimated net impact on load of incentive-driven efficiency improvement programs, load-shifting programs (largely time-of-use rates) and the load displacement non-utility generation program. The Basic Load Forecast was prepared in July for rate finalization purposes considering the following: the 1989 Customer Estimates (completed individually in April 1989 and compiled in aggregate in June 1989); the results of annual econometric models utilizing data to the end of 1988; the forecasts of the monthly models (primarily the State-space model) using weather-corrected load data to June, 1989; and, various end-use analyses.

The Basic Load Forecast underlying this projection grows at 3.2% per year on average from 1989 to 1994, about 0.2% per year faster than last year. The forecast begins from a level which is 1.7% higher for 1989 than predicted in LF881212. The change in the forecast level for 1989 takes into account a 1% increase to adjust for the error made in projecting actual 1988 growth (the basis of an update to LF881212 for the OEB) and a further 0.7% included at the time of rate finalization to incorporate the impact of higher than expected second quarter 1989 load growth. That growth is attributed to very strong residential and commercial sector demands, given a slight decrease in direct industrial sales relative to the previous year. In particular, a significant increase in residential air-conditioning demand is evident on the system. The 1990 forecast was raised 0.3% to 2.9%, despite the weakness expected in the economy as a whole, in light of the continuing fast pace of commercial building starts in 1989 whose impact will be felt on completion in 1990. A preliminary estimate of the impact of the Goods and Services Tax (GST) on the load growth rate in 1991 is about a 0.5% reduction in growth. As the forecast selected for rate finalization without taking into account the GST was about that amount below the model projections, the original forecast is being maintained, subject to further analysis of the GST. The rapid expansion of residential and commercial building space has pushed load growth above economic growth in 1987-88 and is forecasted to continue to do so until 1990. Thereafter, Basic Load growth more in line with economic growth is projected.

The net load impact of Hydro's electrical efficiency improvement programs is projected to cumulate to 2.6 TW.h by 1994 (up from 1.4 TW.h in LF881212) while load displacement non-utility generation in excess of that which would occur without Hydro's intervention is expected to reduce load by 2.5 TW.h in 1994 (up from 1.8 TW.h in LF881212). The net decrease in primary energy due to these programs relative to last year's forecast is 1.9 TW.h in 1994. The impact on peak of load-shifting programs has been revised down from a total of 655 MW in 1994 in LF881212 to 575 MW in this forecast.

1.1.1 The Short-Term Primary Load Forecast

The 1989 Short-Term Primary Load Forecast for the total system is summarized in Table 1.1.1:

Table 1.1.1: Total System Primary Demand

Year	December 1-Hour Peak			Energy					
		Annual Growth				Annual Growth			
	MW	MW	%	Avg MW	TW.h	Avg MW	%	TW.h	%
Short Term									
1988*	22933			15300	134.4				
1989	23668	735	3.2	15889	139.2	588.5	3.8	4.8	3.6
1990	24235	567	2.4	16294	142.7	405.1	2.5	3.5	2.5
1991	24934	699	2.9	16720	146.5	426.3	2.6	3.7	2.6
1992**	25648	714	2.9	17248	151.5	528.5	3.2	5.0	3.4
1993	26224	576	2.2	17665	154.7	416.9	2.4	3.2	2.1
1994	26787	563	2.1	18071	158.3	406.1	2.3	3.6	2.3
Avg Increase									
1988-94		642	2.6			462	2.8	4.0	2.8
1989-94		624	2.5			437	2.6	3.8	2.6

* Actual

** Affected by Leap Year

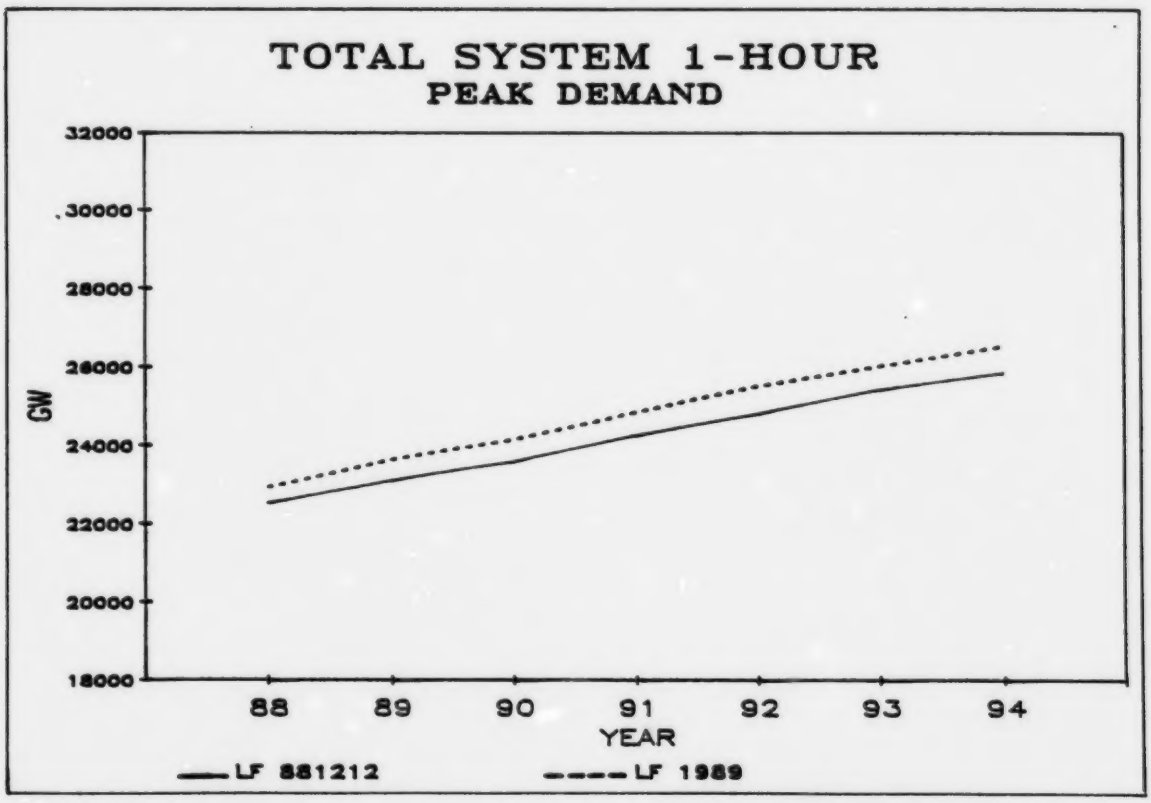
1.1.2 Comparison with Load Forecast 881212 - Peak Demand

The level of the primary peak forecast in 1994 is 3.5% or 914 MW higher than projected last year. The weather-normal forecast for 1989 is 540 MW higher than LF881212. Between 1989 and 1994 the Basic Load Forecast for 1989 versus that for 1988 indicates a decline in system load factor and an associated increase in the rate of growth of peak relative to energy. The differential impact of demand management is not significant, so this pattern also appears in the 1989 primary peak forecast when compared with the 1988 forecast. As a result, primary peak grows at about the same rate as energy between 1989 and 1994, rather than slightly slower as was the case last year. The annual load factor in the short-term Basic load forecast is built-up from monthly load factors at the customer level.

Table 1.1.2: 1-Hour Peak Demand

Year	Annual Growth MW	Annual Growth %	Primary Load Forecast 881212 MW	Primary Load Forecast 881212 %	Change from Primary Load Forecast 881212 MW	Change from Primary Load Forecast 881212 %
1988*	22933		22545		388	1.7%
1989	23668	3.2%	23128	2.6%	540	2.3%
1990	24235	2.4%	23597	2.0%	638	2.7%
1991	24934	2.9%	24269	2.8%	665	2.7%
1992	25648	2.9%	24816	2.3%	832	3.4%
1993	26224	2.2%	25445	2.5%	779	3.1%
1994	26787	2.1%	25873	1.7%	914	3.5%
Avg. Increase						
1988-94		2.6%		2.3%		.30%
1989-94		2.5%		2.3%		.24%

* Actual



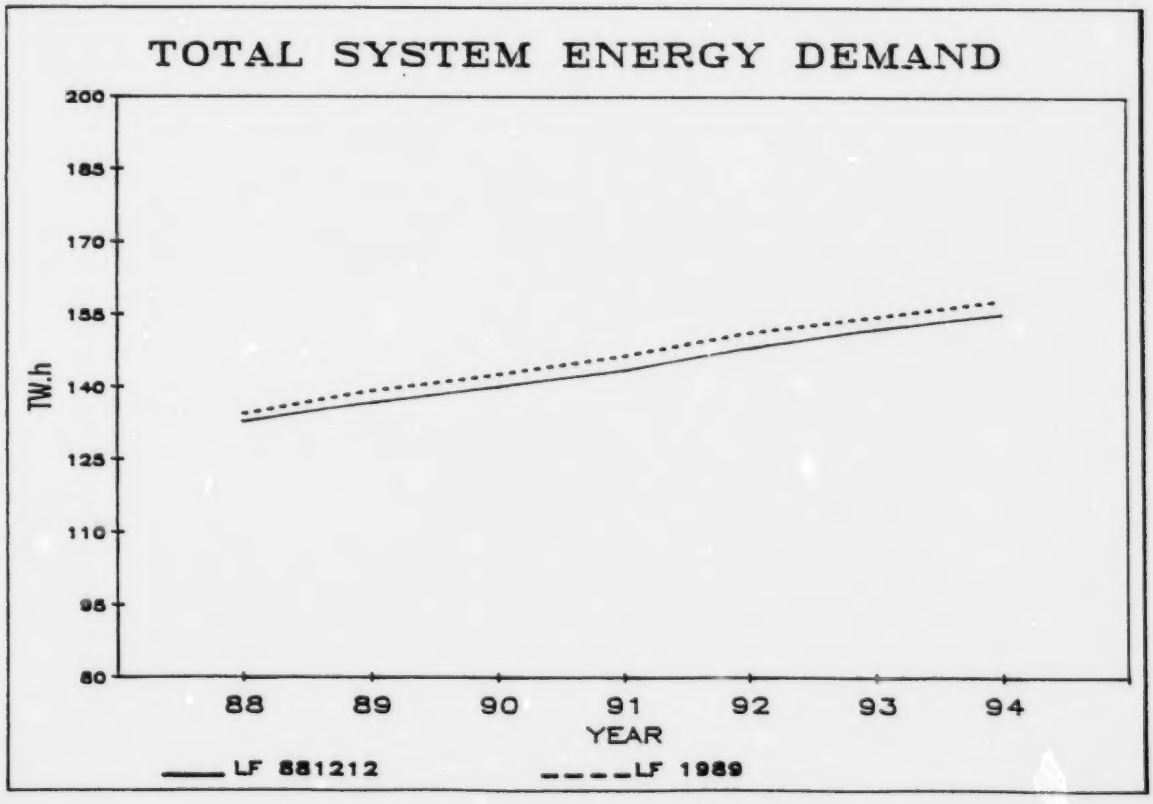
1.1.3 Comparison with Load Forecast 881212 - Energy Demand

The level of the energy forecast is approximately 2.0% higher on average than the 1989 Short-Term Forecast for the period 1989 to 1994. Most of the difference in energy demand in the short-term forecast occurs by 1990.

Table 1.1.3: Energy Demand

	1989 Primary Load Forecast			Primary Load Forecast 881212			Change from Primary Load Forecast 881212	
Year	Avg MW	TW.h	% Inc TW.h	Avg MW	TW.h	% Inc TW.h	TW.h	%
1988*	15300	134.4		15147	133.0		1.4	1.0%
1989	15889	139.2	3.6%	15631	136.9	2.9%	2.3	1.7%
1990	16294	142.7	2.5%	16002	140.2	2.4%	2.5	1.8%
1991	16720	146.5	2.6%	16396	143.6	2.4%	2.9	2.0%
1992**	17248	151.5	3.4%	16886	148.3	3.3%	3.2	2.2%
1993	17665	154.7	2.1%	17385	152.3	2.7%	2.4	1.6%
1994	18071	158.3	2.3%	17745	155.4	2.0%	2.9	1.9%
Avg. Increase								
1988-94			2.8%			2.6%		
1989-94			2.6%			2.6%		

* Actual
** Affected by Leap Year



1.1.4 Derivation of the Primary Load Forecast from the Basic Load Forecast

The Basic Load Forecast is the forecast of the demand for electricity (at the generator) without taking into account the net impact of Hydro's incentive-driven programs to influence the level and timing of electricity demands on Ontario Hydro. The Basic Load Forecast does take into account energy efficiency improvements and load displacement non-utility generation that are driven by normal market forces. The Primary Load Forecast is the forecast of power and energy which Ontario Hydro would normally generate or purchase in order to meet the demands of its customers in Ontario. It incorporates the net impact of demand management and load displacement non-utility generation programs.

Electrical generation that is not owned or operated by Ontario Hydro and that is consumed by the generator reduces the demand on Ontario Hydro's system. It is known as load displacement non-utility generation (LD-NUG). Nearly all industrial cogeneration currently in operation in Ontario falls into this category. It is projected that about 100 MW of LD-NUG would be added without Hydro's assistance by 1994. With Hydro's programs, it is anticipated a further 333 MW will be installed by 1994. Both the natural and program-driven LD-NUG estimates are higher than last year for the Short-Term Forecast horizon. Hydro's programs have an even greater impact on encouraging non-utility generation for sale to the Hydro grid. This generation is considered a supply resource for planning purposes.

The net load impact of Hydro's programs to improve electrical efficiency in Ontario ramps up much more rapidly in this forecast than last year. The Energy Management Branch is accelerating the rate it plans to introduce programs and is broadening their scope as well. Programs providing financial incentives and valuable customized information will be available in all sectors that use electricity to motivate efficiency gains that would not otherwise be expected to take place. An outline of these efficiency improvement programs (EIP) is contained in the Energy Management Branch Business Plan. The net impact estimates presented here are based on an assessment of the projections contained in this plan made by the Economics and Forecasts Division in consultation with the Energy Management Branch.

The forecasted impact of the load-shifting (L-S) programs by 1994 has been reduced from 655 MW in LF881212 to 575 MW in this forecast. The estimated impact of time-of-use rates has not been altered, but less emphasis is now being placed on direct load control in this period. A survey, undertaken in parallel with the collection of the Customer Estimates for peak load for 1989-94, suggests the forecast for the first year's load-shifting is in the right ball park.

Table 1.1.4 shows the Basic Load Forecast for peak and energy (in terms of GW.h and average megawatts). It also summarizes the annual net impacts of EIP, L-S and LD-NUG. The Primary Load Forecast is derived by subtracting the net program impacts from the Basic Load Forecast. Basic energy is projected to grow at an average annual rate of 3.2% between 1989 and 1994; Basic peak grows at 3.5%.

It is the Basic Load Forecast that may be forecasted using statistical models built on past load data. In future, to maintain consistency in the historical data set as demand management impacts contribute to reducing the measured primary load, basic load will need to be estimated by subtracting the estimated net program impacts from the observed primary load data. This will allow the model forecasts to continue to be a valuable guide to future growth rates.

Table 1.1.4: 1989 Short-Term Forecast - Derivation of Primary from Basic

December Peak - MW

Year	Basic	Annual Growth MW	Annual Growth %	EIP	L-S	LD-NUG	Primary
1988A				0	0	0	
1989	23816	883	3.9%	17	77	54	23668
1990	24578	762	3.2%	81	161	101	24235
1991	25517	939	3.8%	164	244	175	24934
1992	26536	1019	4.0%	277	369	242	25648
1993	27435	899	3.4%	411	491	309	26224
1994	28272	837	3.1%	577	575	333	26787
Av % Inc.							
1988-1994		890	3.5%				2.6%
1989-1994		891	3.5%				2.5%

Energy - GW.h

Year	Basic	Annual Growth GW.h	Annual Growth %	EIP	L-S	LD-NUG	Primary
1988A	134395			0	0	0	134395
1989	139331	4936	3.7%	55	0	93	139183
1990	143778	4447	3.2%	296	0	750	142732
1991	148458	4680	3.3%	695	0	1296	146466
1992	154516	6058	4.1%	1212	0	1794	151510
1993	158879	4363	2.8%	1839	0	2292	154748
1994	163358	4479	2.8%	2585	0	2467	158305
Av % Inc.							
1988-1994		4827	3.3%				2.8%
1989-1994		4805	3.2%				2.6%

Energy Av MW

Year	Basic	Annual Growth Av Mw	Annual Growth %	EIP	L-S	LD-NUG	Primary
1988(A)	15299.9			0	0	0	15299.9
1989	15905.4	605.4	4.0%	6.3	0	10.6	15888.5
1990	16413.0	507.6	3.2%	33.8	0	85.6	16293.6
1991	16947.2	534.2	3.3%	79.4	0	147.9	16719.9
1992	17590.6	643.4	3.8%	138.0	0	204.2	17248.4
1993	18136.8	546.2	3.1%	209.9	0	261.6	17665.3
1994	18648.1	511.3	2.8%	295.1	0	281.6	18071.4
Av % Inc.							
1988-1994		558	3.4%				2.8%
1989-1994		549	3.2%				2.6%

(A) - Actual

1.2 Inputs to the Forecast

The short-term load forecast is prepared considering the following information.

(1) Regional Estimates - Each year a survey is made of all the Corporation's customers to determine their expectations for their own future peak demand. Known future customers are also taken into account.

(2) Economic Conditions and Trends - The most recent economic activity and energy price forecasts are assessed directly as well as used as inputs to a range of models for forecasting electricity demand.

(3) Forecasting Models - The Load Forecasts Department has estimated a variety of single-equation annual and monthly forecasting models. They range from the purely statistical analysis of past data (Box-Jenkins) to conventional structural econometric specifications. No one model has developed a clearly superior track record; methodology development is on-going.

These three sources of forecast information are supplemented by other indicators where available (such as results from the end-use models).

This section provides a brief description of each of the above inputs.

1.2.1 Regional Estimates

To initiate the short-term forecasting process, the Load Forecasts Department asks the regional offices to provide six years of estimates of the peak for each wholesale customer (municipalities and direct industrial) and total retail customers. The regional staff, using the results from two time-series models provided by the Load Forecasts Department, together with their knowledge of the local economy and consultation with large customers, prepare an estimate for each month of the current year and the first forecast year. For the subsequent four years, only December forecasts are made.

The customers are canvassed each spring for forecasts of their own peak demands. Their estimates, which form the starting point for 1989 Short-Term Forecast, were 1.5% higher than the 1988 Customer Survey for 1989, increasing to a 2.6% difference by 1993.

Table 1.2.1: Sum of Customers' Loads - MW

Average Monthly 1-Hour Non-Coincident Peaks

Year	1989 Customer Survey	1988 Customer Survey	Differences	% Change
1989	21056	20799	257	1.2
1990	21990	21548	442	2.1
1991	22844	22402	442	2.0
1992	23796	23262	534	2.3
1993	24764	24127	637	2.6
1994	25781	N/A	N/A	-

The municipal utilities, the area offices, and the direct customers have the best and most detailed information about plans in their own neighbourhoods and businesses. They have the best perspective on new developments requiring electricity, on local business anomalies and on the continuity of existing sales. Their estimates are believed to be quite reliable for the near term.

1.2.2 Economic Conditions and Trends

Economic Outlook

Fiscal and monetary restraint are visibly affecting the North American economy. In fact, the slowdown has gained considerably in breadth and depth over the past six months. Interest-sensitive sectors are especially vulnerable. Real estate sales are waning, consumer and business loan demands have softened significantly and savings rates have risen. Provincial exports are straining under the dual pressures of flagging external demand and the high Canadian dollar. Moreover, the marked rise in inventories during the early part of 1989 foreshadows sluggish output and employment growth in the months ahead.

There is still no indication, however, that a recession is materializing. Interest rates have more or less stabilized, business investment for new plant and equipment remains impressive and consumers (while adjusting to the new realities) do not appear to be retrenching like they did in 1982. Assuming car sales on both sides of the border hold up reasonably well and also that businesses are able to better control stock levels, Ontario economic growth is expected to average 2.5% in 1989 and 1.3% in 1990. Nonetheless, given the importance of manufacturing to the province, Ontario will probably be outperformed by both Canada and the United States.

Assuming only a modest slowdown in 1990, only a soft recovery is likely for 1990 and beyond. Growth is forecast to bounce back to 3.6% in 1991 and 1992 but to ease somewhat lower to 3.2% in 1993. Average growth for the entire period 1991 to 1995 is calculated at 3.3%.

Table 1.2.2: Economics and Forecasts Division's Outlook

Gross Product - $1981 Billion

	CANADA				ONTARIO			
	1988 Sept.	% Increase	1989* Sept.	% Increase	1988 Sept.	% Increase	1989* Sept.	% Increase
1987	422.602	3.85	426.411	4.48	168.228	4.23	170.198	4.45
1988	438.661	3.80	447.779	5.01	174.789	3.90	178.538	4.90
1989	449.627	2.50	459.869	2.70	179.508	2.70	183.001	2.50
1990	459.070	2.10	466.767	1.50	183.637	2.30	185.380	1.30
1991	473.760	3.20	479.370	2.70	190.064	3.50	192.054	3.60
1992	489.868	3.40	496.148	3.50	197.287	3.80	198.968	3.60
1993	505.544	3.20	513.513	3.50	203.206	3.00	205.335	3.20
1994	521.721	3.20	530.459	3.30	209.302	3.00	211.700	3.10

* Historical numbers revised
Numbers are taken from Economic Summary sheet provided in the Short-Term Economic Forecast, September 1988 and 1989.

Energy Price Trends

Electricity prices are projected to remain almost constant in real terms for the next few years. Electricity's price competitiveness relative to both fuel oil and natural gas deteriorated in recent years - especially in the 1986/1988 period when weak crude oil prices and deregulation of the natural gas market resulted in lower retail prices for both fuels in Ontario. Some improvement in electricity's relative price is projected in the early 1990's as both natural gas and fuel oil prices are projected to escalate faster than inflation in this period.

1.2.3 Short-Term Forecasting Models

The following paragraphs provide a brief outline of the single-equation models built with annual and monthly load data that the Load Forecast Department is currently working with. Greater detail concerning model development, specification and forecasts is given in Appendix 2. Table A2.1 in the appendix presents the model projections along with some of the other forecast information used in determining the short-term load forecast.

1) Monthly Models

For several years the Load Forecasts Department has been gaining experience with several more advanced forecast modelling techniques. These use monthly data and comprise single and multiple variable time series methods as well as a regression technique that focuses on modelling patterns in the remaining error terms. The forecasts prepared using these techniques perform best for time horizons less than about 18-24 months.

Since January 1988, the Load Forecasts Department has adopted a weather-correction methodology which adjusts for wind speed, illumination and humidity in addition to the temperature effects previously taken into account. This methodology was used to create a historical time-series of monthly weather-corrected data that goes back to 1971. The models estimated by EPRI's FORECASTMASTER software using these data had considerably better fits than in the past. (The methodology used to weather-correct actual load data is described in Appendix 1).

The single variable time series model, called the Box-Jenkins technique after the original developers, presumes that all the information relevant to predicting the future of a variable is contained within the data history of the series to be predicted. Box-Jenkins models may be expected to forecast well in periods when the factors which affect the variable being forecasted continue their recent trend. For economic data this is unlikely to be longer than about two years and is often considerably less time. Predicted changes to the background environment of the forecasted variable that are out of keeping with recent trends will not be reflected in the projection made by the Box-Jenkins model. For this reason, little weight is currently being given to the Box-Jenkins forecast. Multivariate time series methods are an elaboration of the single variable technique which permit key causal variables to be included in the forecasting equation. The form of multivariate time series analysis in Forecast Master which is used by the Load Forecasts Department is called State-space modelling. The state-space model's forecast is still dominated by recent patterns in electricity use; a forecasted change in the trend of GDP growth has less impact on the forecast than the same change would have in one of the annual econometric models.

A third monthly modelling technique that has been used by the Load Forecasts Department is known as 'Auto Pro'. This methodology is a hybrid of standard regression techniques and the time series methods used by the other two model types just described. It is no longer used as an input to the forecast because it has become apparent that this model form only yields stable parameters on Hydro data when estimated using techniques that are known to bias the coefficients.

The State-Space forecast has picked up the recent strength in electricity sales and is projecting 3.9% for 1989, 3.7% for 1990 and 4.2% per year for 1991-93. As noted above, beyond two years into the future, this technique becomes less reliable.

ii) Annual Models

The partial adjustment and error correction models described in LF881212 have been updated using the new real Ontario GDP data set developed by the Ontario Ministry of Treasury and Economics and Statistics Canada. The updated equations are very similar to those used last year, though both exhibit a slight reduction in own-price elasticity. The forecasts of both models are quite close averaging 3.0% and 3.1% per annum over the period 1988-1994 for the error correction and partial adjustment respectively. The average of the models' forecasts for load growth for 1989 is 2.9%, for 1990 it is 2.3% and for 1991 it is 3.6%. Growth in 1992-1994 averages 3.3%.

1.3 Determining the Basic Load Forecast and the Unallocated Load

The customer surveys, economic trends and forecast model results constitute most of the data used in generating the forecast, but any other indicators of economic performance and electricity sales are considered as well. The forecast considers all available information taking into account the suitability of each methodology for projecting particular years of the forecast period.

The 1989 Customer Survey resulted in forecasts of 4.4% for 1989 and a steady 4.1% for 1990-1994. To reconcile the total of the customer estimates to the Basic Load Forecast, an amount may be added or subtracted. This amount has been termed unallocated load.

The load forecast for Basic energy for 1989 is 4.0%, up 1.8% from LF881212. The increase adjusts, in part, for the increase in the 1988 actual growth rate relative to forecast of 1%, which may largely be explained by weather effects. The remaining adjustment brings the forecast up to the rate forecasted by the state-space model with information to the end of June. Second quarter load growth was stronger than expected and this was picked up by the model.

June and July 1989 showed indications of a significant increase in residential air-conditioning load. Industry estimates suggest an additional 250,000 central air-conditioning units will be installed in 1989 in a market which was about 860,000 units in 1988. The increase in air-conditioning load explains a large part of the increase in summer peak and contributes significantly to the increase in annual energy. The effect of unusually rapid growth in the saturation of air-conditioning is expected to continue into 1990.

The forecast for load growth in 1990 has been raised slightly to 2.9% though the GDP forecast has been held at 1.3%. The increase takes into account higher than anticipated commercial building starts in the first half of 1989. These will typically show up in terms of increased demand in 1990. The upward adjustment moves the forecast closer to the state-space forecast but there still is a large gap between the monthly and annual model forecasts for the year. The forecast for 1991 and beyond rely increasingly on the annual models and bear in mind the electricity intensity trends in the early years of the long-term load forecast. The economy is expected to recover in 1991 from the slower growth rate of 1990. However, the impact of high real interest rates in 1989 and 1990 on residential and commercial building completions will be delayed to 1991. This is expected to bring the ratio of electricity demand growth relative to economic growth down from the high values of the 1987 to 1990 period.

The Goods and Services Tax (GST) is now expected to be introduced in 1991. A preliminary estimate of the impact of the new tax on electricity demand in 1991 is 0.5%. This takes into account both lower real GDP growth forecasted in the short-term and higher real prices for electricity and natural gas. The price effect is only anticipated to alter residential electricity consumption as the

cost increase is likely to be passed through into higher prices by other customers. When Hydro's annual econometric model forecasts were updated in October 1989 to provide a preliminary estimate of the impact of the G.S.T., their forecasts for growth averaged about 3.1% in 1991. As the load growth rate for 1991 selected for rate finalization was below the model forecasts by roughly the amount of the G.S.T. impact, the recommended Basic forecast has not been changed. Further analysis of the extent of the impact of the G.S.T. will be undertaken early in 1990.

The forecasts for 1992-1994 average 3.2% per year which is slightly less than the annual models would suggest and is about 0.1% per slower than real GDP. Neither the customer estimates nor the monthly models are expected to be able to capture the transition to a slower rate of GDP growth combined with a potentially over-built commercial sector in this period.

Table 1.3: Sum of Customers' Loads - MW

Average Monthly 1-Hour Peaks

Year	Customer Survey	Unallocated Load	1989 Short-Term Load Forecast
1989	21056	-36	21020
1990	21990	-304	21686
1991	22844	-423	22421
1992	23796	-541	23255
1993	24764	-763	24001
1994	25781	-1083	24698

The amounts of unallocated load shown in the table are more negative than those used in last year's report.

1.3.1 Weather

The expanded Short-Term Forecast includes monthly forecasts of energy and peak demand. The monthly actual demands, as well as the annual actual totals, are strongly influenced by weather conditions. For the purpose of the forecast, normal weather conditions, as measured by the recorded averages, are assumed. For example, the December peak is assumed to occur on the most extreme weather day in December, which is assumed to have temperature, wind and illumination conditions equal to the typical extreme day in December.

1.3.2 Losses

In addition to estimates of customer demand, transmission losses are incorporated in the Basic Load Forecast. These losses averaged approximately 4.0% of customer energy for the period 1981 to 1983. Since 1984 losses have been gradually increasing, reaching 4.6% in 1986. In 1987 and 1988 losses dropped slightly to 4.5%. These higher than average losses will continue for a few more years due to the delay in obtaining approval for adequate transmission out of the Bruce nuclear complex. There will be no relief from this situation until the new 500 kV line from Bruce to London is brought into service, currently scheduled for August 1, 1990.

Forecast losses are assumed to be 4.5% for 1989, 4.4% in 1990 and 4.2% for the remaining years of the forecast.

1.3.3 Capacity Interruptible Loads

In general, capacity interruptible loads are those for which a customer contracts for power which may be interrupted by Ontario Hydro in exchange for a lower rate. Interruptible loads and Control Centre Controlled loads are subtracted from the Primary Load Forecast when System Planning derive their Planning Firm Load series.

Table 1.3.3: Capacity Interruptible Loads - East System

Sum of Non-Coincident Customers' Capacity Interruptible Load
December Monthly Peak - MW

	1989	1990	1991	1992	1993	1994
Interruptible						
25 Hz	29	29	29	29	29	29
60 Hz	789	779	797	828	842	845
Total	818	808	826	857	871	874
In Terms of Generation*						
25 Hertz MW	23	23	23	23	23	23
60 Hertz MW	616	608	622	647	658	660
Total	639	631	645	670	681	683

* At time of East System Peak

Currently only one customer in the West System has a capacity interruptible contract. West System's December Interruptible load in terms of generation is as follows:

1989 - 36 MW
1990 - 36 MW
1991 - 36 MW
1992 - 36 MW
1993 - 36 MW
1994 - 36 MW

1.4 Performance of Load Forecast 881212 in 1989

As noted in Section 1.3.1 the Load Forecast is prepared assuming normal weather conditions. Actual weather conditions may deviate significantly from normal for a short period, though usually are not a large factor affecting annual energy. Annual peak, however, is quite weather-sensitive. Performance of the forecast is most appropriately measured against the weather-corrected actuals.

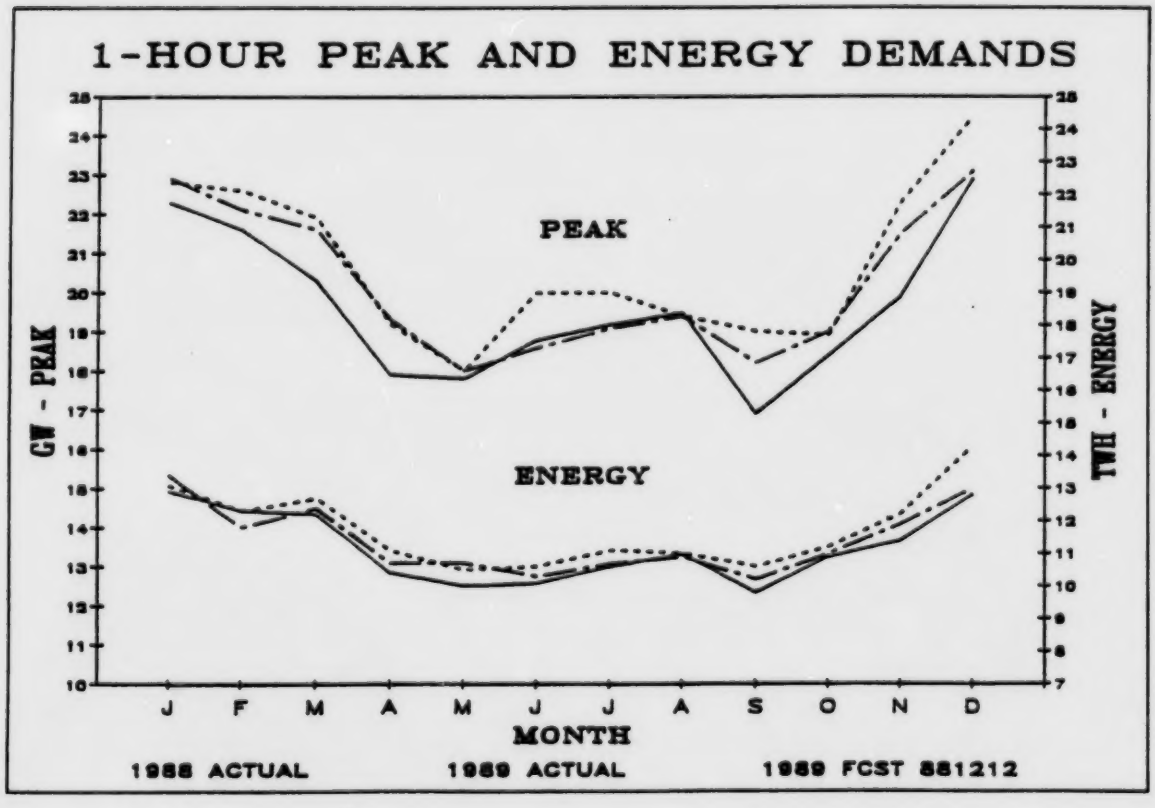
1.4.1 Actual Primary Demand Versus Forecast 881212

This section evaluates the performance of last year's forecast against the actual monthly peak and energy data for 1989. With the exception of the 1-hour peak for January and May, and energy in January and May, Load Forecast 881212 under-forecasted demand. The greatest deviations from the forecast were for the months of June and July, when the weather was very hot and humid. For the first nine months of 1989, the actual demand was, on average, 2.1% greater in peak and 1.7% greater in energy than the Load Forecast 881212.

Table 1.4.1: Load Forecast Performance

	1-Hour Peak - GW					Energy - TW.h				
	Actual		% Yr/Yr	1989 Forecast	%	Actual		% Yr/Yr	1989 Forecast	%
	1988	1989	Growth	881212	Dev.*	1988	1989	Growth	881212	Dev.*
Jan	22.3	22.8	2.2	22.9	-0.4	12.9	13.1	1.7	13.4	-1.6
Feb	21.6	22.6	4.8	22.1	2.4	12.3	12.3	0.1	11.8	4.0
Mar	20.3	21.9	7.8	21.6	1.3	12.2	12.7	4.7	12.4	3.0
Apr	17.9	19.2	6.9	19.3	-1.0	10.4	11.1	6.4	10.7	3.3
May	17.8	18.0	1.1	18.0	0.0	10.0	10.5	5.0	10.7	-1.5
Jun	18.8	20.0	6.3	18.6	7.4	10.1	10.6	4.4	10.3	1.5
Jul	19.2	20.0	4.1	19.1	4.8	10.6	11.1	5.0	10.7	4.3
Aug	19.5	19.4	-0.3	19.4	0.2	11.0	11.0	0.2	10.9	1.1
Sept	16.9	19.0	12.7	18.2	4.6	9.8	10.6	8.0	10.2	3.4
Oct	18.4	18.9	2.8	19.0	-0.5	10.9	11.2	2.8	11.0	1.5
Nov	19.9	22.3	11.8	21.5	3.6	11.4	12.2	7.1	11.9	2.8
Dec	22.9	24.5	6.7	23.1	5.8	12.8	14.3	11.7	13.0	10.1
Avg	19.6	20.6	5.1**	20.2	2.0	134.4+	140.8+	4.7**	136.9+	2.8

* Per cent deviation from forecast.
\+ Total
** Based on Annual Average



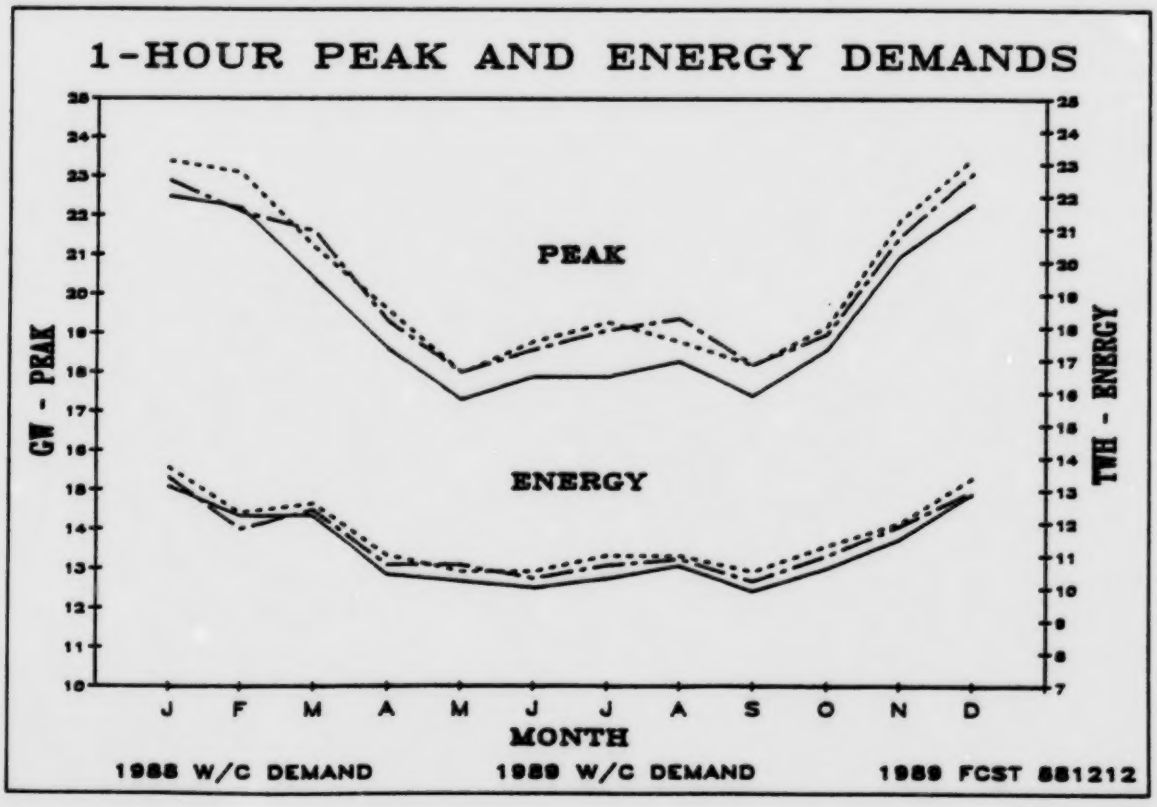
1.4.2 Weather-Corrected Primary Demand Versus Forecast 881212

Table 1.4.2 below summarizes the monthly performance of Load Forecast 881212 in 1989 on a weather-corrected basis.

Table 1.4.2: Load Forecast Performance

	1-Hour Peak - GW					Energy - TW.h				
	Weather Corrected Demand		% Yr/Yr Growth	1989 Forecast 881212	% Dev.*	Weather Corrected Demand		% Yr/Yr Growth	1989 Forecast 881212	% Dev.*
	1988	1989				1988	1989			
Jan	22.5	23.4	3.7	22.9	2.0	13.1	13.7	4.2	13.4	2.5
Feb	22.2	23.1	4.1	22.1	4.7	12.2	12.3	0.5	11.8	4.0
Mar	20.4	21.2	3.8	21.6	-2.0	12.2	12.6	2.9	12.4	1.7
Apr	18.6	19.6	5.6	19.3	1.3	10.4	11.0	5.7	10.7	2.4
May	17.3	18.0	3.8	18.0	-0.3	10.2	10.5	3.0	10.7	-2.0
Jun	17.9	18.8	5.0	18.6	0.7	10.0	10.5	4.9	10.3	2.5
Jul	17.9	19.3	7.3	19.1	0.8	10.3	11.0	6.5	10.7	2.5
Aug	18.3	18.8	2.5	19.4	-3.1	10.7	11.0	2.5	10.9	0.7
Sept	17.4	18.2	4.9	18.2	0.3	9.9	10.5	5.6	10.2	2.6
Oct	18.6	19.2	3.3	19.0	0.9	10.6	11.3	6.5	11.0	2.4
Nov	21.0	21.9	4.4	21.5	2.1	11.5	12.0	4.6	11.9	1.3
Dec	22.3	23.5	5.2	23.1	1.4	12.9	13.4	4.4	13.0	3.7
Avg	19.5	20.4	4.5**	20.2	0.8	134.1+	139.8+	4.2**	136.9+	2.1

* Per cent deviation from forecast.
\+ Total
** Based on Annual Average



2.0 THE LONG-TERM PRIMARY LOAD FORECAST - 1995 TO 2015

2.1 Highlights

The recommended 1989 Primary Load Forecast for energy is 3.5% and 4.7% higher in the years 2000 and 2010 respectively than the 1988 Primary Load Forecast (LF881212). The increase in peak demand is slightly greater in these years due to differences in the peak and energy growth rates in the first few years of the forecast.

The 1989 Primary Load Forecast for energy averages 2.1% annual growth from 1988-2010, up from 1.9% per annum in the 1988 Load Forecast (starting with the 1988 actual). Similarly, Basic energy growth averages 2.5% per year over this period, up from 2.3% in last year's forecast.

The change in the 1989 Primary Load Forecast is almost entirely due to changes in the Basic Load Forecast.

About half of the increase in the Basic Load Forecast occurs in the short term. It may be attributed to the increase in the actual over the forecast for 1988 and faster growth rates forecast for 1989-1991 based on model projections (offset somewhat by a negative impact of the Goods and Services Tax). From 1994 to 2010, the Basic Load Forecast averages 2.2% annual growth, up from 2.1% in 1988. With no change in the GDP forecast, slightly higher real electricity rates and significantly lower competing fossil fuel prices, the small net increase in growth is due to the increased electricity intensity implicit in both the econometric and end-use model forecasts. The industrial and commercial sectors of the econometric model have been completely respecified and the end-use forecast now relies on Hydro's application of the EPRI end-use models called REEPS, COMMEND and INDEPTH. One outcome of all these model improvements, from a forecasting perspective, is a slightly higher ratio of electricity demand growth per constant dollar of GDP than was characteristic of the forecasting systems used last year.

Despite the increase in the growth rates in electricity demand relative to LF881212, there remains a sharp contrast between the growth rates in the current long-term forecast and the experience of the last six years when load growth averaged about 5% per annum. This is appropriate. The years 1982-1988 consisted entirely of an outstanding economic recovery from the worst recession in Ontario in 50 years. During this period, real GDP grew at nearly 6% per year for reasons that cannot be sustained over the long term.

A more balanced perspective for the long-term may be gained by including the weak years of the current economic cycle - the early 1980's - in the analysis of recent history. Since 1980, real GDP has averaged 4.3% growth per annum and load growth has averaged 3.8%. In fact, the 1980 load forecast contains a very accurate forecast for 1989, though the path to it was not predicted accurately. As the long-term fundamentals are not perceived all that differently now than in 1980, the year 2000 load forecasts made in 1980 and in 1989 are very close as well. The decline in labour force growth rates in the 1990's will slow GDP growth and load growth nearly one percent relative to the 1980's. Higher electricity intensity growth rates offset the slightly lower productivity performance projected for the 1990's (relative to the 1980's) and so the other major factors determining load growth in the long term are neutralized.

2.1.1 Load Forecast 891211

Table 2.1.1: Long-Term Primary Load Forecast - 891211

	December 1-Hour Peak			Annual Energy		
		Annual Growth*			Annual Growth*	
Year	MW	MW	%	TW.h	TW.h	%
Short Term						
1988(A)	22933			134.4**		
1989	23668	735	3.20	139.2	4.8	3.56
1990	24155	487	2.06	142.7	3.6	2.55
1991	24854	699	2.89	146.5	3.7	2.61
1992	25517	663	2.67	151.5**	5.0	3.44
1993	26031	514	2.01	154.7	3.2	2.14
1994	26550	519	1.99	158.3	3.6	2.30
Long Term						
1995	26979	565	2.34	161.5	3.8	2.63
2000	29214	447	1.66	177.2	3.1	1.95
2005	31545	466	1.60	191.5	2.9	1.61
2010	34709	633	2.01	210.6	3.8	1.99
2015	38452	748	2.16	232.9	4.5	2.12

(A) - Actual

	Average Annual Growth			
Period***	MW	%	TW.h	%
1988-1990	611	2.63	4.2	3.04
1988-1995	578	2.35	3.9	2.66
1988-2000	462	2.04	3.2	2.33
1988-2005	507	1.89	3.4	2.10
1988-2010	535	1.90	3.5	2.06
1988-2015	575	1.93	3.6	2.06

* Values for long term are for five-year period ending in year specified
** Leap Year
*** Using actual 1988 values

2.1.2 Comparison with Load Forecast 881212 - Primary Energy Demand

The Primary energy forecast is about 2% higher than LF881212 through to the mid-1990's. By the mid-1990's, the 1989 Basic Load Forecast is about 3% above last year's forecast, but the net impact of electricity efficiency improvement (EEI) and load displacement non-utility generation (LD-NUG) programs increases sufficiently to narrow the gap in the primary load forecasts.

In the year 2000, primary energy is 3.5% higher than in LF881212. This is a slightly larger increase than in the Basic Load Forecast as the energy reduction due to EEI and LD-NUG programs is marginally lower than estimated in LF881212. By 2010, primary energy demand is forecast to be 4.7% higher than last year. The Basic energy forecast increases by roughly the same percentage.

Table 2.1.2: Primary Energy Demand

Year	1989 Recommended Primary Load Forecast (TW.h)	Primary Load Forecast 881212 (TW.h)	Increase Over 881212 TW.h	Increase Over 881212 %
Short Term				
1988*	134.4 (Actual)	133.1	1.3	1.0
1989	139.2	136.9	2.3	1.7
1990	142.7	140.2	2.5	1.8
1991	146.5	143.6	2.9	2.0
1992*	151.5	148.3	3.2	2.2
1993	154.7	152.3	2.4	1.6
1994	158.3	155.4	2.9	1.9
Long Term				
1995	161.5	158.2	3.3	2.1
2000	177.2	171.2	6.0	3.5
2005	191.5	188.2	3.3	1.8
2010	210.6	201.1	9.5	4.7
2015	232.9	NA		
Growth Rates				
1988-2000	2.33	2.12		
1988-2005	2.10	2.06		
1988-2010	2.06	1.89		
1988-2015	2.06			

* Leap Year

2.1.3 Comparison with Load Forecast 881212 - Primary Peak Demand

The 1989 primary peak demand forecast differs from the corresponding 1988 forecast by an amount which is fairly consistently higher than the differences in the two energy forecasts. This is almost entirely because the difference between forecast and actual for 1988 for peak was 1.7%, whereas it was 1.0% for energy. Since the impact of Load Shifting programs is almost identical to the amounts projected in LF881212, the only other reason for differences between the peak and energy comparisons would be small differences in the load factors of energy reductions due to EEI and LD-NUG programs.

Table 2.1.3: December 1-Hour Peak

Year	1989 Recommended Primary Load Forecast (MW)	Primary Load Forecast 881212 (MW)	Increase Over 881212 MW	Increase Over 881212 %
Short Term				
1988	22933 (Actual)	22545	388	1.7
1989	23668	23128	540	2.3
1990	24155	23597	558	2.4
1991	24854	24269	585	2.4
1992	25517	24816	701	2.8
1993	26031	25445	586	2.3
1994	26550	25873	677	2.6
Long Term				
1995	26979	26252	727	2.8
2000	29214	27918	1296	4.6
2005	31545	30793	752	2.4
2010	34709	32889	1820	5.5
2015	38452	NA		
Growth Rates				
1988-2000	2.04	1.80		
1988-2005	1.89	1.85		
1988-2010	1.90	1.73		
1988-2015	1.93	NA		

2.1.4 Comparison of Primary to Basic Load Forecast

The Basic Load Forecast takes into account all the factors affecting the future demand for electric power and energy except those activities which Hydro may undertake in future to influence the amount and timing of electricity demands on Ontario Hydro. The Primary Load Forecast remains the forecast of the electric power and energy which Ontario Hydro must generate or purchase to meet the electricity demand of its customers in Ontario. It is derived by subtracting the expected future net impact of Electrical Efficiency Improvement (EEI), Load Shifting (L-S) and Load Displacement Non-Utility Generation from the Basic Load Forecast (LD-NUGs). The net impact on load of these programs may be due to direct financial incentives or other means by which Ontario Hydro incurs costs to provide a targetted benefit to customers (e.g. customized information such as energy audits).

The net load impact of Hydro's programs is expected to reduce peak power requirements in the year 2000 by 10.4%. Their 3.4 GW contribution by the year 2000 represents about 35% of the 9.7 GW increase in peak demand forecasted between 1988 and 2000. The forecasted net load impact of EEI, L-S and LD-NUG programs is described in Section 5.

Table 2.1.4: 1989 Load Forecast - Primary vs Basic

Year	December Peak - MW Basic	Impact of Incentives	Primary	% Diff.	Energy - GW.h Basic	Impact of Incentives	Primary	% Diff.
Short Term								
1988(A)	22933	0	22933	0.0	134395	0	134395	0.0
1989	23816	148	23668	0.0	139331	148	139183	0.1
1990	24498	343	24155	1.4	143784	1046	142738	0.7
1991	25437	583	24854	2.3	148458	1991	146467	1.3
1992	26405	888	25517	3.4	154516	3006	151510	1.9
1993	27242	1211	26031	4.4	158879	4131	154748	2.6
1994	28035	1485	26550	5.3	163358	5052	158306	3.1
Long Term								
1995	28761	1782	26979	6.2	167590	6098	161492	3.6
2000	32616	3402	29214	10.4	190052	12853	177200	6.8
2005	35961	4416	31545	12.3	209541	18036	191505	8.6
2010	39613	4904	34709	12.4	230824	20252	210571	8.8
2015	43690	5238	38452	12.0	254576	21668	232908	8.5
Growth Rates								
1988-1994	3.4		2.5		3.3		2.8	
1988-1995	3.3		2.3		3.2		2.7	
1988-2000	3.0		2.0		2.9		2.3	
1988-2010	2.5		1.9		2.5		2.1	
1988-2015	2.4		1.9		2.4		2.1	
1990-2000	2.9		1.6		2.8		2.2	
2000-2015	2.0		1.8		2.0		1.8	

(A) - Actual

2.1.5 Comparison of Basic Load Forecast 891211 with Basic Load Forecast 881212

The 4.8% increase in the 1989 Basic Load Forecast (energy) in the year 2010 relative to the 1988 Basic Load Forecast may be attributed to the increase in the base year, faster growth in the short term and an expectation of rising electricity intensity in the economy beyond 2005. The latter effect is the outcome of the changes in the econometric and end-use models made this year. The real Ontario GDP forecast is unchanged after the early 1990's. Electricity prices are about 4% higher in real terms by 2010 than last year and natural gas prices, while still rising in real terms, are 12% lower than projected last year. Both these price effects, other things equal, would tend to reduce electricity demand slightly.

The increase in the Basic Load Forecast may be traced to much faster than expected residential and commercial sector demand growth in 1988. The increase in the 1989 to 1994 period as well as in the longer term may be attributed to a faster rate of electrification of the commercial sector than was the case in previous forecasts.

Table 2.1.5: Basic Load Forecast Comparison

Year	December One-Hour Peak - GW				Energy - TW.h			
	Load Forecast 881212	Load Forecast 891211	Difference GW	Difference %	Load Forecast 881212	Load Forecast 891211	Difference TW.h	Difference %
Short Term								
1988	22.55	22.93*	0.39	1.7	133.0	134.40*	1.4	1.0
1989	23.24	23.82	0.58	2.5	137.07	139.33	2.26	1.6
1990	23.84	24.50	0.66	2.8	140.54	143.78	3.24	2.3
1991	24.76	25.44	0.68	2.7	145.07	148.46	3.39	2.3
1992	25.61	26.41	0.80	3.1	150.63	154.52	3.89	2.6
1993	26.46	27.24	0.78	2.9	154.93	158.88	3.95	2.5
1994	27.08	28.04	0.96	3.5	158.53	163.36	4.83	3.0
Long Term								
1995	27.77	28.76	0.99	3.6	162.52	167.59	5.07	3.1
2000	31.46	32.62	1.16	3.7	184.12	190.05	5.93	3.2
2005	34.94	35.96	1.02	2.9	204.54	209.54	5.00	2.4
2010	37.64	39.61	1.97	5.2	220.31	230.82	10.51	4.8
2015	NA	43.69			NA	254.58		
Growth Rates								
1988-1994	2.8	3.4			2.8	3.3		
1988-1995	2.8	3.3			2.8	3.2		
1988-2000	2.7	3.0			2.7	2.9		
1988-2015	NA	2.4			NA	2.4		
1990-2000	2.8	2.9			2.7	2.8		
2000-2015	NA	2.0			NA	2.0		
1995-2000	2.5	2.6			2.5	2.6		
2000-2005	2.1	2.0			2.1	2.0		
2005-2010	1.5	2.0			1.5	2.0		
2010-2015	NA	2.0			NA	2.0		

* Actual

2.1.6 Comparison of Net Load Impacts of Demand Management and Load Displacement Programs, LF891211 versus LF881212

The major changes to the Electrical Efficiency Improvement (EEI) program in the 1989 Load Forecast are in the short term and the very long term. The Energy Management Branch is ramping up its programs more rapidly than expected last year. By 1994, EEI programs are now forecast to reduce Basic Load by 577 MW, which is 263 MW more than in LF881212. The net load impact in the year 2000 is the same as projected last year, 2000 MW. By 2010, however, EEI programs are expected to contribute a total of 3200 MW, a 700 MW increase over the amount estimated last year.

The net impact on peak load of load-shifting programs is almost the same as in last year's forecast. The difference occurs in the period to 2000 when the exclusion of some direct load management programs alters the time profile of the impacts. The estimated net impact in the year 2000 remains 1000 MW and in the 2010 it is 1265 MW, also as it was last year.

The net load impact of load displacement non-utility generation increases much more rapidly in the early years of the forecast than it did last year. However, by 1997 the forecast paths cross and by the year 2000 the net load impact is 135 MW lower than in LF881212. By 2010, the net impact of load displacement generation programs is 545 MW lower than in last year's forecast. This is in part due to an increase in the estimated contribution of natural load displacement generation. Nonetheless, the decrease on the demand side is more than offset by an increase in purchased non-utility generation (which is treated as a supply resource).

When all the net load impacts of all the programs to influence the amount and timing of electricity demand in Ontario are aggregated there is only a small difference between the 1988 and 1989 forecasts. This is shown in Table 2.1.6.

Table 2.1.6: Comparison of Cumulative Load Impact of Incentive-Driven Demand Management and Load Displacement, LF891211 vs LF881212 (December Peak MW)

	LF891211			LF881212	
Year	L-S/ EEI*	LD**	Total	Total	Difference in Total
Short Term	94	54	148	114	34
1989	242	101	343	242	101
1990	408	175	583	493	90
1991	646	242	888	790	98
1992	902	309	1211	1014	197
1993	1152	333	1485	1220	265
1994					
Long Term	1425	357	1782	1514	268
1995	3000	402	3402	3537	-135
2000	3995	421	4416	4151	265
2005	4465	439	4904	4749	155
2010	4780	458	5238	NA	NA
2015					

* Load Shifting (Time-of-Use Rates) and Electrical Efficiency Improvement Programs

** Load Displacement Non-Utility Generation

2.1.7 Selection of Recommended Primary Load Forecast

The recommended Primary Load Forecast is derived by subtracting the forecast of the net load impact of program-driven demand management and load displacement generation from the recommended Basic Load Forecast. The latter is determined considering as input the long-term load forecasts produced by the Econometric Energy Model of Ontario (EEMO) and the end-use models. Both are spliced into the Short-Term Load Forecast for 1989 - 1994.

The recommended total system Basic Load Forecast was determined sector by sector. In both the residential (including agriculture) and industrial sectors, the 1988 to 2015 average annual growth rates differ by less than 0.1% between the EEMO and the end-use model results. In both cases, the end-use results generated by REEPS and INDEPTH were slightly lower than those of the econometric model. The forecasts from the new end-use models were selected for these two sectors.

In the case of the commercial sector, EEMO projected 3.2% average annual growth to 2015 while COMMEND, the new EPRI end-use model, forecasted 2.6%. The quality of the historical data available for the commercial sector is the weakest of the three sectors which makes modelling and forecasting this sector very challenging. In light of the uncertainties surrounding future growth in commercial electricity demand, the recommended forecast splits the difference between the two model forecasts for this sector.

The sectoral forecasts for both the end-use and econometric models are presented in Sections 4 and 5 respectively. Table 2.1.7 provides the result obtained when the selected forecasts for each sector are used to derive the recommended Basic Load Forecast.

Table 2.1.7: Summary of Forecasts

	Ontario Hydro Basic Energy Demand Model Comparison (TW.h)		Official Load Forecast 891211 (TW.h)			
Year	EEMO*	End-Use*	Basic	Impact of EEI***	Load Displacement	Primary
1988 Actual	134.4	134.4	134.4	0.0	0.0	134.4
1989	136.9	138.8	139.3	0.1	0.1	139.2
1990	138.8	141.5	143.8	0.3	1.0	142.7
1995	169.1	167.6	167.6	3.4	2.6	161.5
2000	197.8	186.8	190.1	9.9	3.0	177.2
2005	220.2	205.7	209.5	14.9	3.1	191.5
2010	243.1	224.7	230.8	17.0	3.3	210.6
2015	267.9	246.8	254.6	18.3	3.4	232.9
Growth Rates**						
1988-2000	3.3	2.8	2.9			2.3
1988-2005	2.9	2.5	2.6			2.1
1988-2010	2.7	2.4	2.5			2.1
1988-2015	2.6	2.3	2.4			2.1

* The End-Use Model and Econometric Energy Model of Ontario Forecasts are described in Sections 4 and 5 respectively.
** Average annual percent change
*** Incentive-driven Electric Efficiency Improvement Programs

2.2 Load Forecast Uncertainty

The 1988 Long-Term Load Forecast introduced a new methodology for deriving the probability distribution associated with the median load forecast. At the same time, an 80% bandwidth was presented rather than the 60% confidence band shown in previous forecast documents. The change in the confidence level of the bandwidth reflected a preference for demand/supply planning purposes expressed by the System Planning Division.

The methodology used to prepare the probability distribution associated with the 1989 Load Forecast is almost identical to the one used last year. Two equations with the same specifications are used to derive first, GDP growth from population growth and second, load growth from GDP growth. The probability distribution associated with compound growth rates of population for each year of the forecast period is then translated into a corresponding distribution for GDP growth. This, in turn, generates a load growth distribution. The bandwidth is slightly

wider beyond the year 2000 than it was last year because the uncertainty in the relationship between GDP growth and load growth is now fully simulated in the long term.

The median load growth rate to 2010 in the 1989 Load Forecast is 2.5%, compared with 2.4% forecasted last year. Because of the shift in the median it is to be expected that the entire probability distribution would shift towards higher values. This is accentuated further by an improvement in the scaling methodology used to align the probability distribution about the median forecast of the two-equation system with the recommended median forecast. The slight skew to the high side seems appropriate given historical experience.

The lower bound of the 80% uncertainty band is set at the 10% point of the distribution about the median load forecast. This means that for any particular year there is a 10% chance that the load will actually fall below the value given for that year. Similarly there is a 10% chance that the load will actually exceed the value given by the upper band.

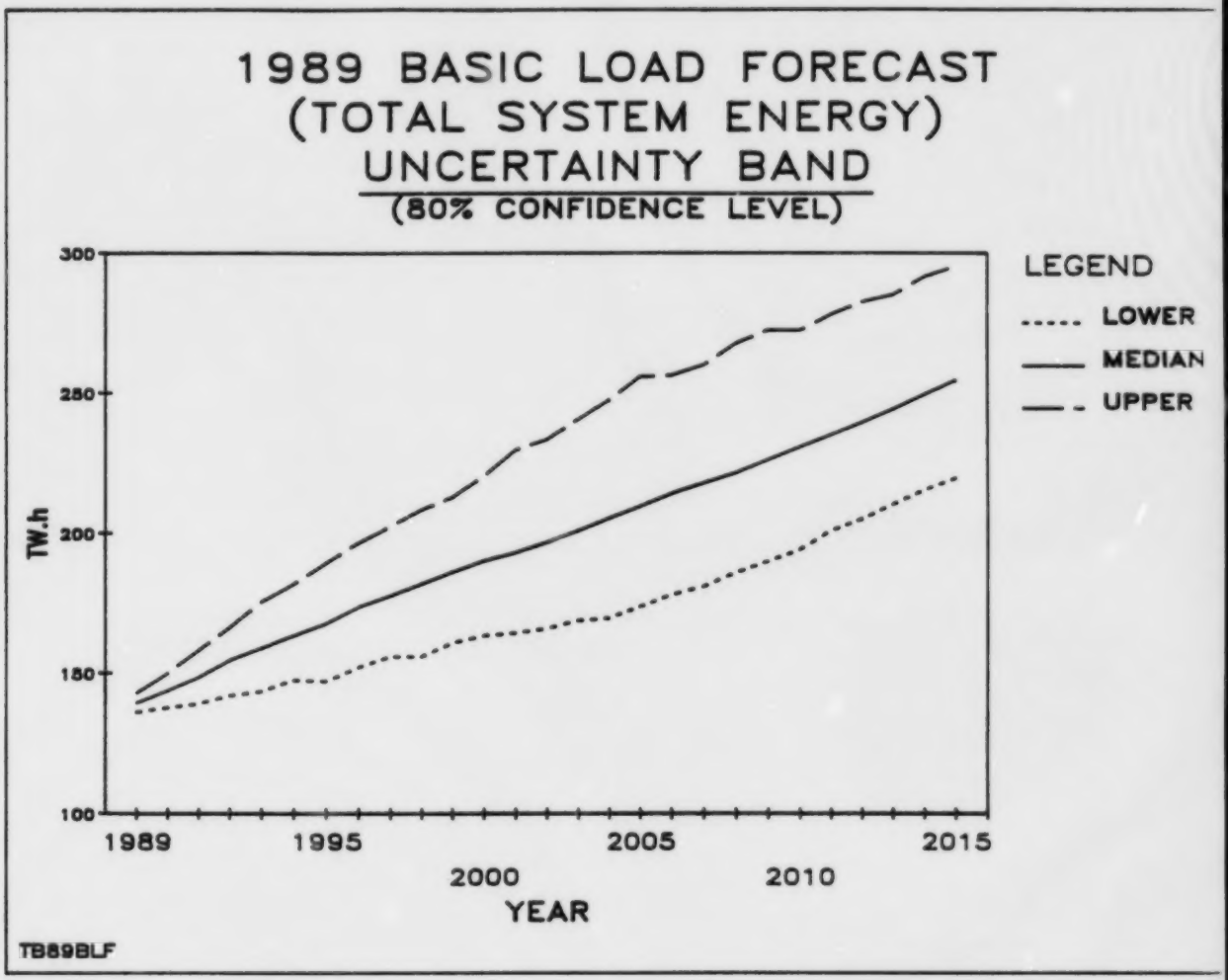
The 80% band has a width of about 60 TW.h in the year 2000 and about 80 TW.h in the year 2010. This translates into a width of 10 GW in the year 2000 and 13 GW in the year 2010, assuming no uncertainty in the system load factor.

The upper bound of the bandwidth (the 90% point on the distribution) is 16% above the median in the year 2000 and 18% above in 2010. The lower bound of the bandwidth, the 10% point on the distribution, is 14% below the median in 2000 and 16% below in 2010. These results indicate the slight upward skew to the distribution.

Table 2.2: Uncertainty Band for Annual Basic Energy (TW.h)

Year	Lower (10%)	Forecast (50%)	Upper (90%)
Short Term			
1988 (Actual)		134.4	
1989	136.2	139.3	142.8
1990	137.8	143.8	150.0
1991	139.2	148.5	158.1
1992	142.5	154.9	166.8
1993	143.6	158.9	175.4
1994	147.5	163.4	181.8
Long Term			
1995	147.0	167.6	189.2
2000	163.9	190.6	220.9
2005	173.7	209.5	255.9
2010	194.1	230.8	272.3
2015	219.7	254.6	295.2
Growth Rates			
1988 - 1994	1.6	3.3	5.2
1988 - 2000	1.7	2.9	4.2
1988 - 2005	1.5	2.6	3.9
1988 - 2010	1.7	2.5	3.3
1988 - 2015	1.8	2.4	3.0

Figure 2.2



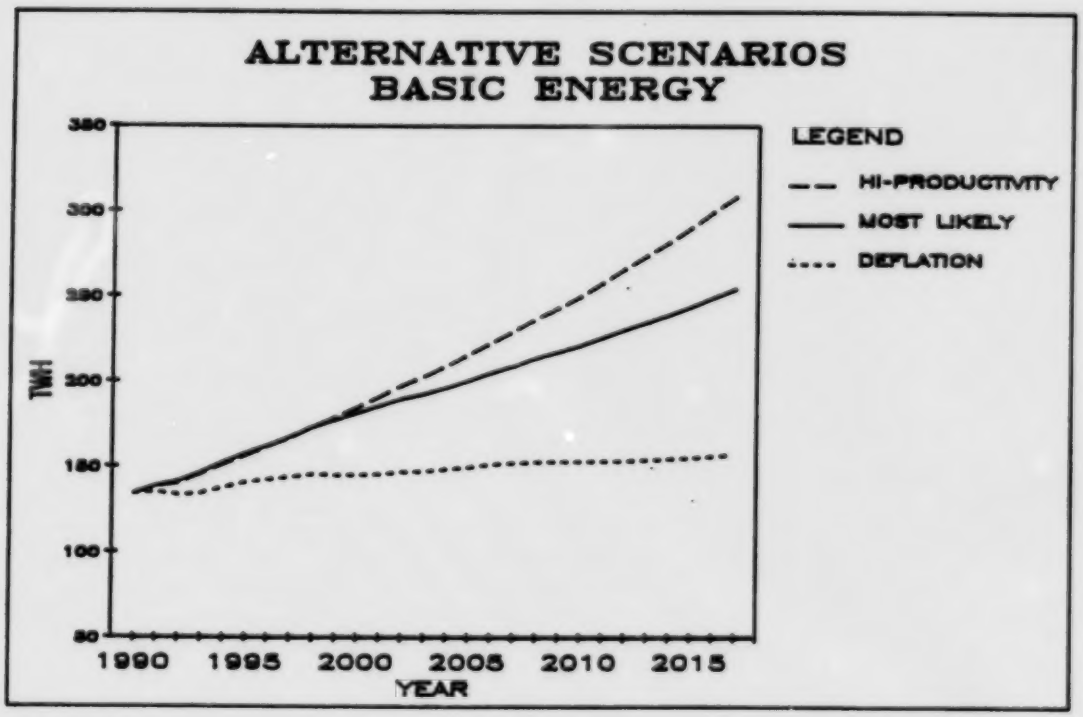
2.3 Alternative Scenarios

In order to gauge the risk of a major change for the assumed economic growth, alternative scenarios are generated. The Economics and Forecasts Division prepares alternative forecasts of the economic environment in addition to the most-likely forecast on which the recommended forecast is based. In this way the impact on energy demand of differing economic situations can be measured. The three scenarios postulated are the Higher Productivity, Higher Inflation and Deflation scenarios. One limitation of these scenarios is that the real electricity prices from the Most Likely is used in all cases. When further information on the costs of the other scenarios is available, they will be re-estimated. The energy demand growth rates for these scenarios as well as the most-likely scenario are given below.

Table 2.3: Basic Energy Annual Growth (%)

Year	Higher Productivity	Most Likely	Higher Inflation	Deflation
1988 - 1994	3.17	3.20	NA	0.99
1988 - 2000	3.28	2.93	NA	0.75
1988 - 2010	3.16	2.49	NA	0.61
1988 - 2015	3.13	2.39	NA	0.60
1990 - 2000	3.47	3.00	NA	0.98
2000 - 2010	3.02	1.96	NA	0.45
2010 - 2015	2.99	1.98	NA	0.51

Figure 2.3



3.0 THE LONG-TERM BASIC LOAD FORECAST - METHODOLOGY AND ASSUMPTIONS

3.1 Methodology

This section introduces the methodologies used to prepare the Basic Load Forecast. In general terms, two approaches are taken to estimating electricity demand in Ontario: 'top-down' econometric modelling and 'bottom-up' end-use modelling. Both attempt to capture the effect of a large number of demographic, economic, energy market and technological factors on electricity demand in the long run. Because they do so at different levels of aggregation, the techniques available for extrapolation into the future differ.

The econometric approach relies on statistical analysis of past energy consuming behavior and forecasts of broad economic aggregates to generate estimates of future electricity requirements. The end-use approach tends to be so specific that historical data sets may not be available for statistical analysis. Instead, expert opinion on key technology or market trends are combined with very detailed forecasts of activity levels in end-use categories to derive the forecast. However, as data quality and detail improve and estimation techniques become more sophisticated, econometric results may increasingly determine many specific end-use forecasts. The hard distinction that once existed between engineering end-use (or process) models and econometric models is becoming less clear cut. The need for the load forecast to be tied to a broad scenario for the economy and at the same time be sufficiently detailed to be useful for analyzing demand management programs is pushing methodology to a common ground. The result will exploit the best of both worlds. Ultimately, end-use models are intended to represent both the Basic and the Primary Load Forecasts in an internally consistent manner.

Ontario Hydro uses both end-use and econometric modelling systems in preparing the Long-Term Basic Load Forecast. The strengths and weaknesses of these models are reconciled judgmentally in order to arrive at a recommended forecast for planning purposes.

In order to facilitate focusing on meaningful differences in the models' analysis of energy markets, both modelling approaches have the following features in common in the course of deriving Basic Load Forecasts:

(1) the same demographic, economic output, and energy price forecasts (summarized below in section 3.2).

(2) the same projections for natural load displacement non-utility generation, line losses and other statistical adjustments.

(3) the same data set (the Market Reference Dataset) with sectoral definitions that are the same for the commercial sector and almost identical for the industrial sector. The residential sector in the econometric model is almost equal to the residential sector plus 'other' in the end-use approach.

(4) the same short-term forecast by sector tuned to total system basic load in 1994.

The end-use models used in this year's forecast are described, along with their results, in Chapter 4. The major change in 1989 is that the EPRI models REEPS, COMMEND and INDEPTH have been used to prepare the forecast. The older energy accounting framework has been retired with the exception of parts of the industrial sector not covered by detailed process models.

The econometric model, EEMO, is described, along with its forecast results, in Chapter 5. The total energy and fuel market share equations for the industrial and commercial sectors have been significantly respecified this year.

3.2 Discussion of Major Assumptions

The three most important factors in any model of the demand for electricity in the long run are the projections of the general level of economic activity, the price of electricity and the prices of other competing fuels. These factors can be incorporated into the models and the forecasting procedure in any of several ways. Because these factors are so central, each of the models has been run using similar assumptions. This approach allows the model results tc reflect important differences in other kinds of assumptions, and helps the forecaster to understand the sources of the differences. The economic and energy price trends used throughout the load forecast are summarized below.

3.2.1 Economic Trends

Economic growth will follow the path outlined in the most-likely forecast of the Economics and Forecasts Division's Economic Outlook, Annual Review 1989. This outlook predicts real economic growth in Ontario averaging about 2.54% year over the period 1988 to 2010 and about 2.44% per year over the period 1988 to 2015. Following the trends in population growth, the economic growth rate is forecasted to slow down steadily.

Ontario population will grow at an average annual rate of 0.8% to the year 2010, taking population to just over 11.4 million. Between 1988 and 2015 population is projected to grow at an average 0.8% per year and reach 11.7 million.

Ontario labour force will grow at an average annual rate of 1.2% to the year 2010, when it will be over 6.6 million. Over the period to 2015, the average annual growth rate is 1% and the labour force reaches a level of 6.8 million.

Commercial floorspace (including apartments) will increase from its present level of 2.6 billion square feet to 3.0 billion square feet by 2010, an average annual rate of increase of 0.8%. By 2015 commercial floorspace increases to 3.1 billion square feet, an average annual growth rate of 0.6% a year from 1988.

Housing stock is projected to grow at 1.5% per annum to 2010, from 3.47 million in 1988 to 4.9 million in 2010. Between 1989 and 2015 housing stock is projected to grow at 1.4% per year and reaches 5.1 million units by 2015.

The outlook assumes that the stability of social, economic, and financial institutions will be retained. No international financial crisis will seriously affect the Canadian financial system. There will be no major supply disruptions in basic commodities, like fuels.

The 1989 Annual Economic Outlook forecasts a level of Gross Domestic Product (GDP) in Ontario of almost $310 billion (1981 dollars) in 2010. After taking into account the difference in the (1988) base since last year's forecast, the level of GDP in 2010 is unchanged from last year's economic outlook. The inflation outlook is unchanged from last year's.

Table 3.2.1: Economic Outlook

	Ontario Real GDP (Millions of 1981$)				Ontario Consumer Price Index (1981 = 100)			
	Fall 1988	%*	Fall 1989	%*	Fall 1988	%*	Fall 1989	%*
1989	179,508	2.7	183,001	2.5	153.5	4.8	155.9	5.8
1990	183,637	2.3	185,380	1.3	160.6	4.6	164.2	5.3
1995	215,581	3.3	218,054	3.3	209.1	4.5	212.6	5.3
2000	247,500	2.8	246,709	2.5	266.9	5.0	271.3	5.0
2005	278,660	2.4	276,715	2.3	348.9	5.5	346.3	5.0
2010	309,175	2.1	309,700	2.3	445.3	5.0	442.0	5.0
2015	341,354	2.0	342,030	2.0	568.3	5.0	564.1	5.0

* Annual Growth Rate 1989 and 1990, 5-year annual average 1995-2015

3.2.2 Energy Prices

Table 3.2.2: International and Domestic Energy Prices - Reference Case Real 1989 Dollars

	Wholesale Prices			Ontario Retail Prices - Residential		
	International Oil U.S. Imports - F.O.B. US$/Bbl	Domestic Oil ORAC Cdn$/Bbl	Natural Gas (Toronto) Cdn$/Mcf	Fuel Oil ¢/L	Natural Gas $/Mcf	Electricity ¢/kW.h
1989	17.00	22.95	2.93	31.90	5.70	6.06
1990	17.40	23.45	2.90	31.30	5.50	6.10
2000	21.50	29.20	4.45	34.00	7.45	6.10
2010	23.20	31.70	5.00	37.20	8.70	6.10
2015	24.00	33.20	5.35	39.00	9.25	6.10

Source: Retail Energy Price Trends, November 1989

The structure of the international oil market and its short-term problems have remained almost unchanged since the 1986 oil price collapse. Demand for oil increased again in 1989, as it has during the last few years, but not sufficiently to alleviate OPEC's problem of allocating demand for its oil among its members. The cartel remains in the difficult position of being a producer left to manage substantial surplus capacity; its major problem remains the ability to bring supply in line with demand. In 1989, the international oil market was much firmer than most analysts anticipated, although last year Ontario Hydro did correctly forecast a price rebound from the weak price of 1988.

In the long run, energy price projections are lower than in last year's forecast. This downward revision results from the analysis of long-term energy markets made for the Thermal Cost Review. As a result of this analysis, international oil prices, as well as Canadian oil prices, are projected to be weaker in the next two decades, but then continue to grow in real terms after 2010. The previous forecast assumed constant prices in real terms after 2003. Therefore, the lower crude oil prices in this forecast are primarily associated with the change in the projected dynamic of the international oil market.

The domestic oil market is expected to continue to be deregulated so that Canadian wholesale oil prices are projected to fluctuate with the trend in international oil prices. In practice, this means with respect to West-Texas Intermediate crude at Chicago, subject to exchange rate and transportation adjustments.

The Canadian natural gas market has made substantial steps toward deregulation since 1985 and now operates in a more market-oriented environment. Natural gas prices have remained very weak during this period. The combination of weak oil prices and the deregulation of the natural gas market at a time when substantial surplus supplies of gas existed, both in Canada and the United States, has created a very competitive market. The major beneficiaries of the new system are the industrial customers who pay now on average about 30% less, in nominal terms, than in 1985.

With continued deregulation in both Canada and the United States and free trade in energy between the two countries, the combination of a tighter U.S. market for gas and the increasing cost of marginal supplies should drive up the price of gas in the 1990's.

The electricity price projection used in preparing this forecast assumes that prices remain constant in real terms throughout the forecast period at the level reached in 1990. This is deemed to be the most realistic and stable median forecast recognizing the uncertainties associated with Hydro's future costs and the impact of actual and potential government policies which would affect the price of electricity to the customer.

Electricity's price competitiveness relative to natural gas has deteriorated, since the mid-1980's. This trend is expected to be extended for another few years due to continuing weakness in the oil and natural gas markets. However, in the long term electricity's relative price is still expected to improve.

3.3 Risks to the Forecast

The principal risks identified for the Basic Load Forecast include variations in the rate of real economic growth, the Ontario Hydro rate levels and structure and the prices of other fuels.

In the forecast, as reported in this document, some of the risks associated with these uncertainties are addressed by the use of three alternative scenarios (in addition to the most likely). Each scenario shows the impact on system demand of a set of coordinated alternative assumptions about economic growth (including population growth) and energy prices. The scenarios allow some explicit consideration of the outcomes possible given underlying conditions different from those envisioned in the central forecast. The forecast of electricity demand made for each of these scenarios indicate a wide range of risk arising from the economic outlook alone.

An 80% confidence band about the median Basic energy forecast was presented in Section 1.8. The methodology used in deriving this bandwidth is designed to capture in a statistical manner, the major uncertainties associated with the Basic Load Forecast. The necessary information is not yet available to derive the probability distribution of the primary load forecast, taking into account the uncertainty associated with the net impact of demand management and load displacement generation on the Basic Load Forecast. In the absence of a better approach, whenever such a bandwidth is required, the probability distribution of the Basic Load Forecast is applied to the Primary Load Forecast as well.

Given the sources of external uncertainty, in addition to the uncertainty attached to the load forecasting process itself, the necessity for care in the use of the load forecast cannot be overstressed. The load forecast cannot be used as only a single line projection; the sources and consequent ranges of forecast error must be considered as well.

For this reason, the probability distribution associated with the median forecast is as important as its central tendency.

4.0 THE LONG-TERM BASIC LOAD FORECAST-RESULTS OF THE FORECASTING MODELS

4.1 End-Use Models Forecast

End-use modelling uses a "bottom-up" approach to energy analysis. It starts with an initial stock of energy using devices. This stock is forecast to grow and alter in response to future sectoral activity levels. The energy efficiency of existing stock, penetration of new technologies with typically higher efficiency, and relative fuel share for each end-use are analyzed at a highly disaggregated level.

Each of the major energy using sectors is modelled separately. This analysis requires forecasts of sectoral activity levels (in physical terms) such as residential housing stock, commercial floorspace and industrial output. The key sectoral activity forecasts were derived by the Economic Forecasts Section in a manner consistent with the Economic Outlook, 1989 Annual Review. To meet the extensive data requirements of the end-use models, the Section produced forecasts for commercial floorspace in each of 12 building types, over 40 industrial product forecasts for 13 industries and forecasts of 3 residential housing types. To produce these forecasts, econometric relationships were developed using explanatory factors such as population, labour force, disposable income, and service and industrial GDP forecasts at the two-digit level. All additional economic parameter forecasts needed to run the end-use models, such as age of head of household, persons per household, cost escalators and interest rates were also obtained from sources within the Division.

For the first time, the new generation of end-use forecasting models obtained from EPRI called REEPS (residential), COMMEND (commercial) and INDEPTH (industrial) were used as the framework for the end-use analysis. Ontario Hydro's older End-Use Model (EUM) was used to address those industries not yet covered by INDEPTH. The EUM's role will diminish as work on INDEPTH progresses. The results of this analysis are the basis of the information presented in the following sections.

Ontario Hydro turned to the EPRI models since they provide a level of sophistication beyond the simplistic "accounting approach" utilized by the EUM. They model the choice, energy efficiency and utilization of electricity consuming equipment directly, using basic economic principles of cost minimization and consumer choice. In addition, fuel prices are an explicit input. Neither of these two properties are present in the EUM.

This is not to say that Ontario Hydro is satisfied with the current level of model development. By explicitly modelling decision-maker behaviour, the current mainframe versions of REEPS and COMMEND present a significant advance over previous models. Neither of these models, however, can accommodate the type of detail required by proposed DSM programs. Models capable of realistically representing end-uses and technologies at the level of detail of targeted DSM programs are critical in producing Basic and Primary forecasts which are interconsistent in their relative assumptions and which can, therefore, fully reflect the impact of DSM programs on energy demand. To meet this need, Ontario Hydro has embarked on a joint project with EPRI to develop the next generation of residential and commercial end-use models. Given the fact that many DSM programs are not yet specified and significant information gaps still exist, these modelling tools must be flexible enough to allow for future growth and enhancement. A PC environment allowing straightforward user interface is planned.

During the last few years, Ontario Hydro has put in a considerable effort towards developing Ontario-specific databases and calibrating the current EPRI models

to reflect more accurately energy usage patterns in the Ontario market. This database development is ongoing and is, in fact, expected to increase to meet the richer analyses planned for the next generation of models.

4.1.1 Residential Sector

The residential sector end-use electricity demand was forecast using REEPS - the Residential End-Use Energy Planning System-developed by the Electric Power Research Institute. REEPS is a microsimulation model that forecasts appliance acquisitions, operating efficiencies, and utilization rates for individual households. Individual household behaviour is modelled using the economic theory of consumer choice. The choices made are sensitive to energy costs, the technological performance characteristics of alternative appliances, and household attributes. REEPS uses the Residential Appliance Survey results for 1988 as a base to represent the household/dwelling characteristics of the population in Ontario. It also uses the results of the 1983 and 1986 surveys to calibrate the model parameters to simulate the energy choices in new dwellings.

Another major change this year is the adoption of Energy Management Branch's sectoral definitions. This definition set differs from the definitions used by Statistics Canada by classifying apartments of five units or over in the Commercial Sector rather than in the Residential Sector. This was done to maintain consistency with the Energy Management Branch and to improve information exchange.

REEPS forecasts the energy decisions for eight major end-uses. These are space heating, space cooling, water heating, cooking, refrigerators, freezers, dish washers and other. Two fuel types are analyzed individually. These are electricity and natural gas. Oil and other (e.g. wood, solar, etc.) constitute the third category.

The main driving variable in the model is the housing stock. Projections of the housing stock are made by the Economic Forecasts Section. These projections are consistent with the forecasts of population growth and economic climate. Assumptions are made regarding the number of people per household, vacancy rates and annual demolition rates to tie the long term population forecast to annual housing completions. The composition of housing completions by building type is determined by an econometric model which forecasts future shares by housing type based on economic and demographic variables such as interest and mortgage rates, disposable income, population by age groups and household formation.

In this year's forecast the following housing completions and total housing stock figures were used:

Table 4.1.1.1

Housing Completions and Total Housing Stock
by Building Type

Year	Total Housing Stock (000)	Total Housing Completions	Completions by Building Type (%) Single Detached	Single Attached	Apartments
1988	3341	88727	65.4	14.4	20.2
1995	3899	66916	50.7	19.5	29.8
2000	4225	62717	52.6	11.9	35.5
2005	4494	52786	45.9	12.5	41.6
2010	4732	50547	37.6	22.5	39.9
2015	4975	50153	37.6	22.5	39.9

A major change in this year's forecast is the expectation of an increase in the share of multi-family units as opposed to single family. This trend is the result of the influence of two age cohorts - the 25-30 year old (non-family) and the aged - both of which are characterized by a desire for a maintenance - free life style.

The shift of apartments into the commercial sector and the trend toward multi-family units result in a lower growth rate in the residential housing stock for this year's forecast. Total occupied dwellings in the Residential Sector are forecast to increase by 1.7% per year over the 1988 - 2000 period, slowing to 0.9% per year for the remainder of the forecast period. This is, on average, 0.1 percentage point lower than the 1988 forecast.

Turning to electricity demand, annual growth in demand over the past 15 years has averaged 3.5%. Recent growth has been higher; over the past 3 years it averaged 6% per year. This recent strong growth has been driven by a number of factors: high construction activity, increasing penetration of traditional end-uses, very strong growth in new appliances and higher household incomes. Strong growth is expected to continue in the short run and slowly begin to moderate towards the end of the century as construction slows down and further efficiency gains are made.

A good measure of electricity consumption patterns is given by the level of electricity use per household. Reliable data on residential electricity consumption patterns are available from 1962 to 1987, as are the housing stock numbers. These data reveal some distinctly different patterns. See Figure 4.1.1.1. During the 1960's and early 1970's electricity use grew at a rate approximately twice that of housing stock. This growth in electricity intensity came mainly from rapid increases in the penetration of virtually all electricity using devices. The end-use stock installed at this time was relatively inefficient. With the energy crisis of the early 1970's, there was a major shift in energy usage patterns. Conservation trends for oil and gas had a spill-over effect on electricity consumption per end-use. Coupled with this trend was the fact that many residential appliances began to reach saturation levels. As well, electricity began to experience increasing competition in the water heating market and actually lost market share.

FIGURE 4.1.1.1

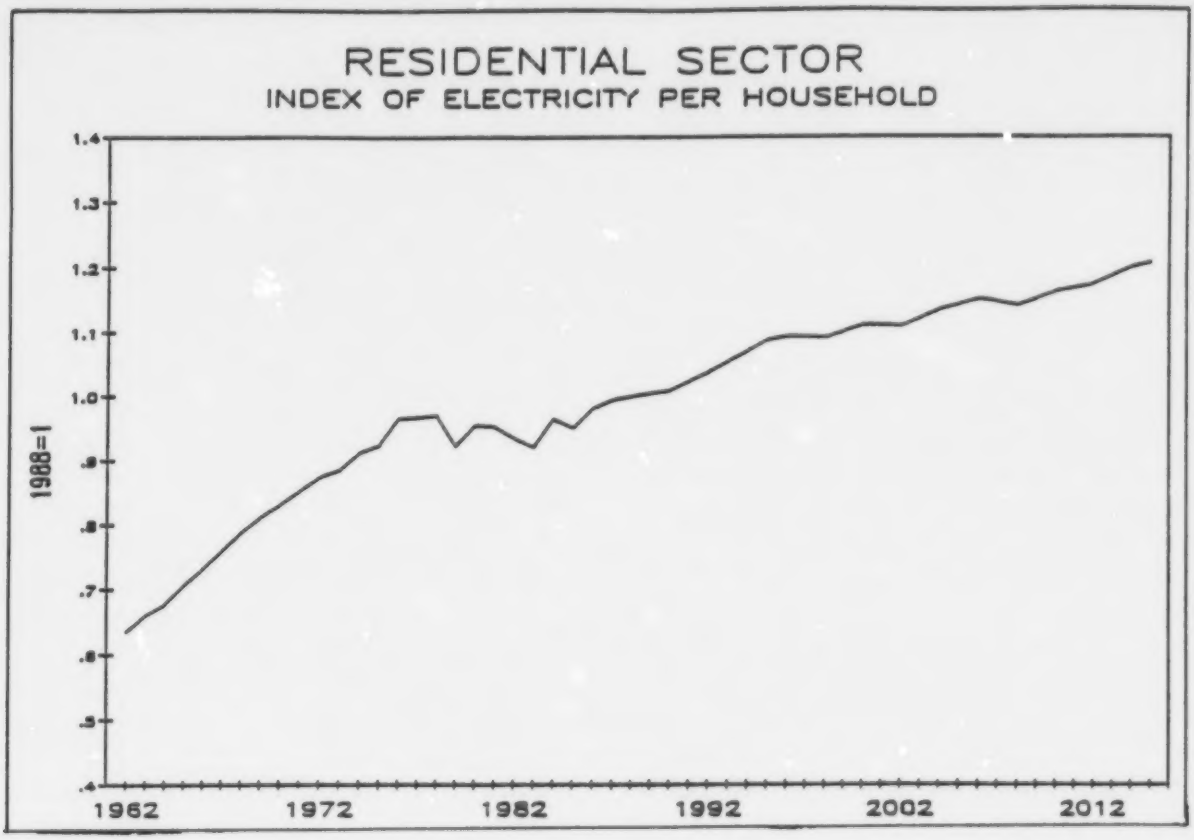
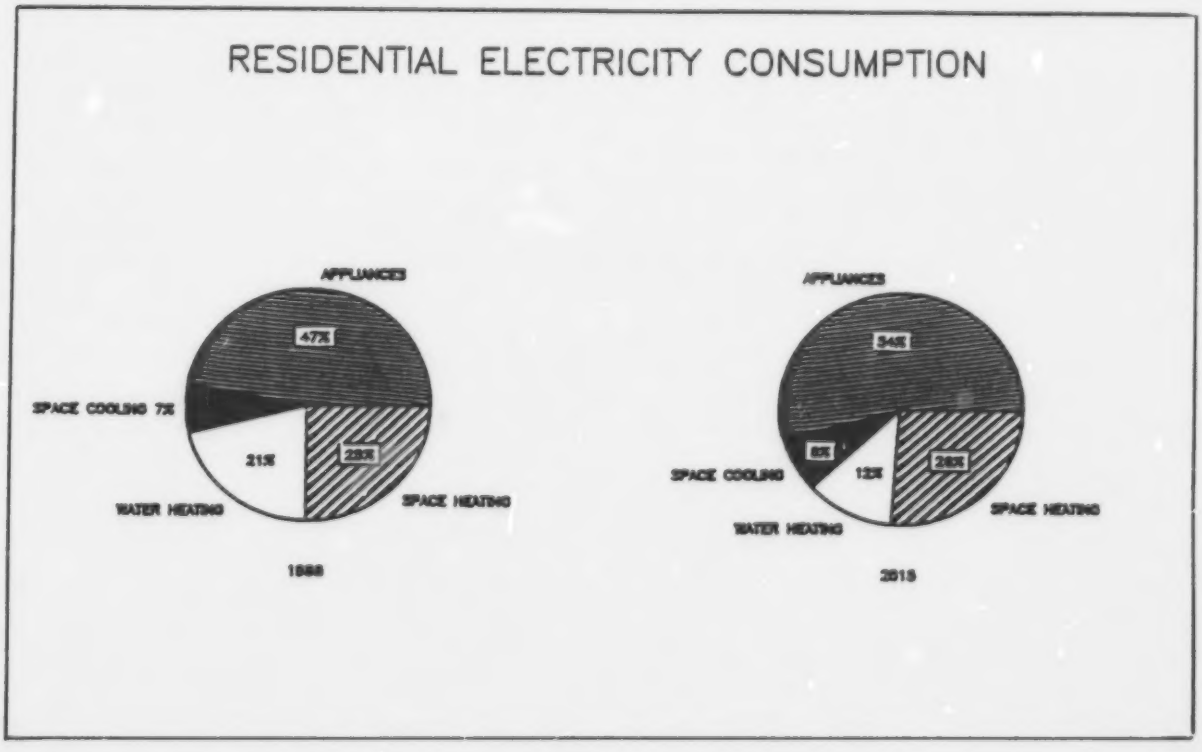


FIGURE 4.1.1.2



Most of the trends identified in the recent past are forecast to continue into the future. Electricity demand in the residential sector is expected to increase by 2.0% per year over the forecast horizon. The growth in electricity demand stems from four factors: increases in housing stock, increases in intensity of use, increases in penetration rates and increases in market share in areas where electricity competes with other fuels. It is not expected, however, that any of these elements will grow at the same rates that were experienced in the 1960's and early 1970's. The electricity growth rate will be moderated by increases in the efficiency with which a given quality of service can be provided. The forecast assumes efficiency improvements in almost all end-uses. These improvements will partly be offset by the trend toward bigger appliances and more features, etc. - factors brought about by the improvement in the general affluence of the society. Electricity use per household will increase by .7% per year as a result of all these developments. The following discussion summarizes the major trends determining electricity demand growth in the principal end-uses in the residential sector.

End-Use Analysis

Space Heating: Approximately 26% of all electricity use in the residential sector is for space heating. Total electricity consumption for this purpose was 9.3 TW.h in 1988. Presently there are about 467,000 all-electric houses in the province, excluding heat pumps. With the heat pumps this figure goes up to 563,000. This represents about 21% of all single-family houses. Oil (20%) and natural gas (59%) make up the bulk of the remaining space heating market. By 2015, it is expected that there will be approximately 1,101,000 all-electric houses, equivalent to 30% of the total stock. Natural gas will remain the dominant space heating fuel with a share of approximately 59%. By itself, the increase in share of electricity for space heating would lead to an average annual rate of growth for electricity of about 2.5%. However, when changes in electricity use per unit (efficiency gains) are factored in, electricity used for space heating grows at roughly 2.0% per annum.

As stated, the difference in the growth rate between market share and electricity for heating can be attributed to efficiency gains and conservation efforts. Note, however, that the overall decrease in the use per unit is not anticipated to be very large. In fact, electricity use per house for resistance heating experiences only a moderate improvement from the present level of approximately 18,000 Kwh per year to 16,250 Kwh per year by 2015. These figures exclude the influence of heat pumps. If heat pumps are included in this average, heating per unit decreases from a present level of 16,600 to 14,350 Kwh, an improvement of 14%, or 0.5% per year, over the forecast period. A factor reducing the rate of improvement is the offsetting effect of increasing new housing size. Recently available information suggests that the average size of a new house has increased by about 500 square feet over the past 15 years. The trend to increasing house size is expected to persist.

Air Conditioning: The air conditioning end-use, although small in the residential sector, is experiencing fairly rapid growth. As a result of the warmer than normal summers experienced in the last 3 years, and partly due to favourable economic conditions, central air conditioning saturation in Ontario jumped from 22% in 1986 to 29% in 1988. Following continued high sales during the first part of this year, the 1989 saturation rate is estimated at 34%. Central air conditioning saturation is forecast to climb to 57% by the year 2015. Heat pumps will contribute 8% to this saturation rate. Room air conditioning, on the other hand, has been very stable, maintaining a saturation rate of 20% over the last 5 years. The forecast assumes a continuation of this trend until 1996 and a gradual decrease to 15.9% by the year 2015 due to a preference for central units. Air conditioning electricity demand in total is forecast to

increase from 2.5 Tw.h to 5.2 Tw.h at the end of the forecast period, an average increase of 2.8% per year.

No account has been made of the effect on efficiency of removing CFCs from air conditioners and refrigerators (for both the residential and commercial sectors). Although CFC removal would make such systems less efficient, there is presently insufficient data on the size of the effect.

The forecasts for space heating and air conditioning both assume that the average weather patterns of the last 30 years will persist throughout the forecast period.

Water Heating: In 1988, roughly 21% of all residential electricity use was for water heating. However, the importance of the electric water heating market for Ontario Hydro is on the decline as the number of houses with oil space heating and electric water heating decreases. By the year 2015, it is expected that water heating will account for only 13% of electricity use in the residential sector. This represents a market share of approximately 37%, down sharply from the present level of 47%. Natural gas is expected to be the predominant fuel for water heating, as it is for space heating.

Appliances: Four appliance types are analyzed separately in REEPS. These are refrigerators, freezers, ovens and dish washers. Thus, REEPS handles 7 end uses individually (space heating, water heating, air-conditioning, 4 appliances). The remaining electricity use in the residential sector is treated jointly under the "other appliances" category. The forecast of electricity use by appliances grows at approximately 2.4% per year. This is almost double the increase in the housing stock. Apart from dish washers, which are expected to increase market saturation from 50% in 1988 to 74% in 2015, appliances in the first group already exhibit highly saturated market levels. It is also evident that the freezers are not as popular as they used to be. The increase in the electricity consumption by appliances, therefore, is driven primarily by the increase in the saturation rate of "other" appliances. The big users in this group with a high potential for market penetration are clothes dryers, saunas, jaccuzzis and whirl pools, microwave ovens, video cassette recorders, personal computers, air cleaners and heat exchangers, humidifiers, electric fans in non-electric central heating, car heaters, and of course, secondary electric heating. Lighting is also covered by this category. The composite saturation index for "other appliances" is expected to double in the next 27 years.

The increase in the saturation rates is partly offset by the improvement in the efficiency of electric equipment. The Table 4.1.2 shows the assumed efficiency improvement for the new stock of appliances. The figures represent the percentage improvement in new stock relative to the average efficiency of the existing stock in 1988.

Table 4.1.1.2

New Appliance Relative Efficiencies

Appliances	%
First Refrigerator	30
Second Refrigerator	20
Freezer	30
Oven	30
Dish Washer	15
Other	10

Along with the efficiency gains comes the change in the quality of service that the customers demand (e.g., larger appliances, more options etc.). Driven by income growth and improvement of living standards, these factors generally work in the opposite direction. As new equipment slowly penetrates the market, the net impact of efficiency gains and higher quality of service can be observed in the average electricity use per appliance figures given in Table 4.1.3.

Table 4.1.1.3

Average Electricity Use Per Appliance
KW.h Per Appliance Per Year

	1988	2000	2015
First Refrigerator	1200	1127	1106
Second Refrigerator	875	832	829
Oven	949	873	869
Freezer	900	839	826
Dish Washer	251	226	223
Other	3513	3945	3193

In households with two refrigerators, the second refrigerator is assumed to be the newer acquisition. Being of more recent vintage, some technological efficiency improvements are already in place leading to lower electricity use and somewhat smaller potential for further improvements.

Summary Tables 4.1.1.4 and 4.1.1.5 give the residential sector electricity consumption levels and annual growth rates by end-use. Figure 4.1.2 shows the composition of final demand by end-use for 1988 and 2015.

Table 4.1.1.4

Residential Electricity Consumption By End-Use (TW.h)

	1988	2000	2015
Space Heating	9.3	12.7	15.8
Air Conditioning	2.5	3.5	5.2
Water Heating	7.6	7.3	7.6
Refrigerator	3.9	4.5	5.0
Freezer	1.6	1.9	2.3
Oven	2.2	2.6	2.9
Dish Washer	0.3	0.4	0.6
Other	9.1	16.8	22.2
Total	36.5	49.7	61.6

Table 4.1.1.5

Residential Electricity Consumption Growth Rates (% p.a.)

	1988-2000	2000-2015	1988-2015
Space Heating	2.6	1.5	2.0
Air Conditioning	3.1	2.7	2.8
Water Heating	-0.3	0.3	0.0
Refrigerator	1.2	0.8	0.9
Freezer	1.6	1.2	1.4
Oven	1.1	0.9	1.0
Dish Washer	2.4	1.9	2.1
Other	5.2	1.9	3.4
Total	2.6	1.4	2.0

4.1.2 Commercial Sector

EPRI's COMMEND model of the Commercial Sector was used exclusively to provide the end-use model estimate of the 1989 forecast. COMMEND represents one of the first major attempts to combine the end-use, bottom-up, approach to energy modelling with the price sensitivities of more aggregate econometric techniques. With this type of approach, decisions about the way energy is used in the commercial sector can be directly linked to factors such as fuel prices and equipment costs.

Like earlier end-use models, COMMEND relates energy use in the commercial sector to the stock of buildings and their energy consumption patterns. The heterogeneity of the commercial sector demands that each building type's usage and level of floorspace be examined separately. In the past, nine building types were examined. For 1989, the number of building types has been expanded to twelve. These are: multi-residential (apartments), offices, elementary/secondary schools, colleges/universities, health, public service, retail, accomodation (hotel/restaurants), recreation, religious/cultural, warehouses and miscellaneous. Note that the new building types are multi-residential, primary/secondary schools and colleges/universities. Non-building related electricity demand (streetlighting, municipal waterworks, construction etc.) in

the commercial sector was examined and forecasted separately from the COMMEND framework.

As was the case last year, the forecasts of floorspace by sub-sector were developed by the Economic Forecasts Section using single-equation econometric models. These models relate historical floorspace stock and construction rates to factors such as population, employment and Gross Domestic Product (GDP). The forecast of total floorspace for the commercial sector as a whole shows a growth from approximately 2.6 billion square feet in 1988 to roughly 3 billion square feet by the year 2015. This corresponds to a growth rate of slightly less than 1% per year compared to about 1.8% per year over the past 20 years. The largest sub-sectors are expected to have very different growth patterns: multi-residential, the largest with approximately 800 million square feet in 1988, will grow at about 1% per year, offices and retail will have growth rates of about 2% and 1.5% per year respectively, while both education sub-sectors are not expected to experience growth in floorspace. In the shorter term, total floorspace for the commercial sector will continue to experience the strong growth of the past three years. By the early 1990's, however, it is expected that construction rates will slow and vacancy rates will begin to increase. Indeed, recent evidence suggests that this second trend has already started to occur in some sub-sectors.

Table 4.1.2.1

COMMEND 1989 Forecast By Building Type

	1988 Sq. Ft. (Mills)	Growth 1988-2015 Sq. Ft. (% p.a.)	1988 Kwh./Sq. Ft.	Growth 1988-2015 Kwh/Sq. Ft. (% p.a.)
Multi-Res	812.3	0.74	7.83	1.57
Offices	359.3	1.68	31.43	1.68
Elem/Secondary	207.1	-0.60	7.71	1.19
Coll/Univ	95.9	-1.76	12.19	1.03
Health	85.4	1.52	18.98	1.28
Pub-Service	69.6	-0.22	10.06	1.36
Retail	249.9	1.41	30.72	1.84
Hotel/Restaurant	96.8	0.40	29.76	2.11
Recreation	52.4	1.51	20.92	1.93
Religion	62.1	-0.56	6.42	0.73
Warehouse	325.1	0.04	7.92	1.83
Miscellaneous	147.1	-0.40	28.79	2.17

The past three years have seen electricity consumption growing in the commercial sector at rates well above those of either the industrial or residential sectors. There are two key reasons for this strong growth: high rates of commercial activity as measured by GDP and construction, and greater intensity of electricity use. COMMEND indicates that the trend towards higher intensity (ie. greater electricity use per square foot) will continue throughout the forecast. This trend will be observed in all sub-sectors. The rate of growth of electricity intensity in different sub-sectors is dependent on a number of factors: increases in penetration of new electrical technologies, increases in electricity's share of the space-heating end-use, and increases in utilization of an end-use. Depending on a subsector's current end-use make-up, each of the above factors will play a greater or lesser role. For example, the use of information processing equipment is expected to have a major impact on the office sub-sector, while electricity's share of space conditioning is expected to show significant growth in hotels/restaurants.

By the year 2015, it is expected that the commercial sector will consume approximately 90 TW.h of electricity, up from the 1988 level of 45 TW.h. This represents a growth rate of about 2.6% per annum. For building-related electricity demand, the growth rate is forecast to be roughly 2.7% per annum. In the shorter term, to 1995, expectations are that electricity demand will grow at a substantially higher rate of 4.3%. This stronger growth in the near term is related to the continued robust rates of construction for the next few years combined with the further penetration of electric space heating and air conditioning systems. In the longer term, the combined effects of a slowing down in the rate of construction and the increasing use of more efficient electrical systems will cause the rate of growth in electricity demand to moderate. Electricity consumption by building type is presented in Table 4.1.2.2.

Table 4.1.2.2

Electricity Consumption by Building Type

Year	1988	2000	2015	Growth Rate 1988 - 2015 (% P.A.)
Multires	6363	9443	11820	2.32
Offices	11292	18781	27764	3.39
Elem/Sec	1597	1758	1870	0.59
Coll/Univ	1169	1108	953	-0.76
Health	1621	2444	3435	2.82
Pub-Service	700	847	950	1.13
Retail	7676	13046	18319	3.27
Accomodation	2881	4637	5639	2.52
Recreation	1096	1939	2756	3.47
Religion	399	425	416	0.16
Warehouse	2576	3690	4251	1.87
Miscellaneous	4235	5395	6790	1.76
Total Building Related	41606	63513	84963	2.68
Total Commercial	45130	67843	89933	2.59

End Use Analysis

The forecast results are presented in Table 4.1.2.3 and Figure 4.1.2.1. COMMEND permits a disaggregated analysis of energy use into equipment efficiency and utilization components. In the following discussion, "efficiency improvement" signifies decreased energy consumption per unit of service due to mechanical or technological changes. "Utilization changes" refer to changes in the amount of energy services required and are distinct from efficiency improvements.

Space Heating: For space heating (as with the other end uses), the key elements that drive demand are share (fuel type), efficiency and utilization. Of these, share is expected to experience the greatest change in the future and will have the biggest impact on electricity demand. Currently, natural gas is the predominant fuel used for space heating with approximately 70% of all floorspace being heated by gas. Electricity (20%) and oil (10%) make up the remainder of the space heating market. By the year 2015, however, a much different market is envisioned. Oil is expected to continue to decrease in terms of share to about 5%, leaving only older, non-retrofitted buildings as users of oil for space heating. Natural gas will still be the predominant fuel used but its share will

have dropped to around 60%. Electricity will experience a substantial increase in share - up to roughly 35% of the space heating market.

There are a number of reasons for this shift in share. First, it is expected that, in the longer term, the trend in the price of electricity will become more favourable thus making electric systems in general more attractive from an operating cost perspective. Second, heat pumps, with their high levels of efficiency and lower operating cost features, will attract a growing number of decision-makers and increase electricity's share of the space heating market. (Note, as well, that heat pumps will be a preferred method of heating due to their dual heating/cooling capability). Third, as building shells improve and internal heat gains increase, the need for large central boilers is diminished and point of use heating systems become more appropriate. The main type of point of use system currently used is the electric baseboard heater. Thus, in spite of its relative inefficiency in comparison to a heat pump, the baseboard heater will continue to be used in large buildings such as offices. Furthermore, baseboard heaters are often preferred in non owner-occupied buildings, such as apartments and small retail stores, because of their individual cost and control capabilities. In this sense, baseboard heaters and heat pumps share the feature that often it is other non-price aspects which determine system selection.

The impact of new, more efficient building envelope and heating system designs coming into service over the forecast period serves to make heating in all new buildings, regardless of fuel type, more efficient. For example, it is expected that a new electrically heated apartment building, in 2015, will have a space heating efficiency roughly 30% better than the current stock average. As well, older buildings will experience some improvements in efficiency due to shell and equipment retrofits. Examples range from the retrofitting of windows in older institutional buildings to the addition of unitary heat pumps to assist in space heating (and air conditioning or water heating).

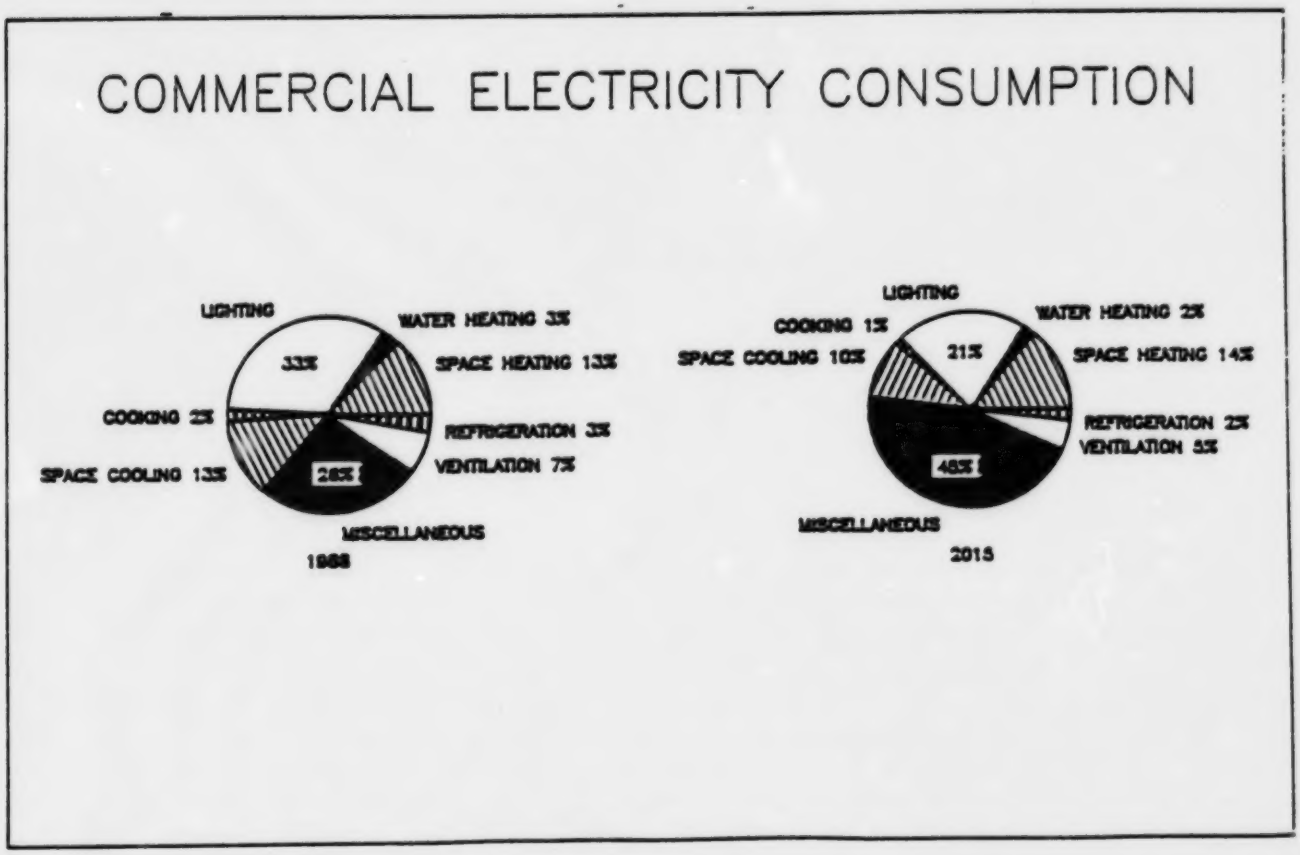
From the perspective of changes in utilization, it is expected that although internal heat gains can cause utilization to decrease, these decreases will be equally off-set by increased use due to longer operating hours and increased emphasis on comfort.

Table 4.1.2.3

Electricity Consumption by Building Type

Year	1988 TW.H	2015 TW.H	Growth Rate 1988 - 2015 (% P.A.)
Space Heat	5.56	11.39	2.69
Air Conditioning	5.41	8.65	1.75
Ventilation	2.97	3.80	0.91
Water Heat	1.06	1.87	2.14
Refrigeration	1.02	1.16	0.47
Cooking	1.22	1.46	0.68
Lighting	13.71	17.57	0.92
Miscellaneous	8.52	39.06	5.80
Non-Building Related	5.68	4.98	-0.49
Total	45.13	89.93	2.59

Figure 4.1.2.1



Air Conditioning: Air conditioning systems will continue to be installed in more and more buildings - both in new buildings and retrofits to existing buildings. In fact, offices, retail, health care and accomodation buildings already have penetration rates for new buildings close to 100%. Even buildings such as schools and cultural institutions are expected to contribute to growth in air conditioning demand. Like their space heating counterparts, air conditioning systems, in general, will become increasingly efficient, reflecting the impact of new technologies such as chillers, and heat pumps. Combining these increases in equipment efficiency with improved thermal shell design indicates that the stock average air conditioning system in place in the year 2015 will be about 10% more efficient than the average system currently in place (for new buildings a 25% improvement over the current stock is envisioned). Counterbalancing these efficiency gains, however, is the effect of greater utilization of air conditioning systems. Increased usage will result from the combined effects of heat gains from the increase in other building loads and longer hours of operation. The net effect is that air conditioning demand should grow at 1.8% per year from its 1988 level of about 5.5 TW.h to roughly 9.0 TW.h by 2015.

Lighting: The single largest user of electricity in the commercial sector is lighting. At present, it accounts for roughly 35% of total commercial sector electricity demand. By the year 2015, its contribution is expected to fall to about 21%. The main reason for this decline is the increased efficiency associated with the installation of energy efficient lighting systems - in particular the replacement of 40 watt bulbs by 34 watt bulbs and, to a much lesser extent, other technologies such as the T8 32 watt bulb, energy efficient ballasts and reflectors. All of these efficiency improvements combine to make the average lighting system about 10% more efficient by the year 2015 than the system currently in place. Note that the average gain is the net effect of 3 factors: technologies that are at least 10% more efficient than the 40 watt bulb, less than 100% penetration of new lighting technologies, and higher density of installation. Virtually all of the improvement in efficiency, based on the replacement of current lighting systems, is expected to occur in the next few years. After that, with no increase in real electricity prices, any further increase in efficiency will depend on significant cost reductions in new, more efficient lighting technologies.

As with the other end uses, trends in utilization will act to counter-balance efficiency gains. Improvements in lighting efficiency will, in part, be offset by greater use of lighting systems in general. This is especially true in the office/retail sectors as longer work days and longer opening hours for stores push up the demand for lighting. This trend has already been identified in many urban areas as strong service sector GDP growth has meant double shifts and more temporary employees resulting in greater lumens per square foot usage.

Thus, it is expected that more floorspace and increased usage will partially negate efficiency improvements in lighting. Demand will grow from the current level of about 14.0 TW.h to 18.0 TW.h by 2015 - an increase representing slightly less than 1% growth per year on average.

Water Heating: Water heating is among the smallest of the end uses in terms of electricity consumed in the commercial sector. It is used primarily in apartments, accomodation sector buildings, schools and health buildings. Like space heating, there are both share and efficiency/usage trends which impact on the water heating market. In terms of efficiency gain, large improvements in efficiency are possible through new technologies such as heat pumps and exchangers. The market penetration of these systems is likely to be modest as water heating is only viewed as an important end use in a few segments of the commercial sector and these technologies are still very costly. However, electricity's share of the water heating market is expected to increase as there

is a strong tendency for establishments that require water heating to choose electricity when they also have an electric space heating system. As a result, water heating electricity demand will increase at about 2.1% per annum - more than twice the growth of total floorspace.

Ventilation: This end use is clearly linked to space heating and air conditioning demand since, as the requirement for heating or cooling changes, so too will the amount of ventilation. The efficiency of the ventilation system is, however, quite independent of the efficiency of the heating or cooling system. Many of the trends with respect to usage identified for space heating and air conditioning have implications for ventilation as well. For instance, as air conditioning demand increases due to increases in interior loads, so too will ventilation loads. More efficient pumps and motors as well as variable speed drives are expected to increase the average efficiency of ventilating systems by about 8%. The forecast for ventilation is for modest growth from the 1988 level of 3.0 TW.h to roughly 4.0 TW.h in 2015.

Refrigeration: Refrigeration is used predominantly in the apartment, retail (groceries), accomodation and warehouse sectors. There is a large potential for efficiency improvement in refrigeration in all of these sectors. Since higher efficiency unitary refrigerators are already impacting the residential market, a similar trend is expected in commercial refrigeration. As a result, refrigeration demand should increase only slightly from its current level of 1.2 TW.h per year to 1.5 TW.h per year in 2015.

Cooking: Like refrigeration and water heating, cooking in the commercial sector is significant in only a few of the building types. As a consequence, its electricity demand is relatively small in absolute terms. Changes in market share are expected as a spillover effect from the changing shares in space heating. Here as well efficiency improvements are expected to be roughly offset by increased usage. The forecast growth rate for electricity demand from cooking for the entire sector is 0.5% per year with efficiency improvements being the key trend.

Miscellaneous: This category includes everything from office machines and personal computers to elevators and walkway heaters. Office machines, personal computers, point of use terminals, and electronic equipment will experience especially strong growth in response to the continuing shift towards an information based economy. Office machines and computers in particular have been shown to have a tremendous effect on both peak and energy demand in the commercial sector. Strong growth in this miscellaneous category is one of the major reasons for the strong growth in electricity demand in the last few years. In fact, this category is forecast to account for 75% of the total growth in demand in the commercial sector. With limited efficiency improvement likely in much of this equipment, it is expected that miscellaneous electricity demand will grow by more than 5% per year from its current level of 8.5 TW.h to 39.0 TW.h by 2015.

Non-Building Related: The forecast focusses on street lighting and municipal waterworks. A single-equation econometric model has been developed to forecast streetlighting directly. This model explicitly accounts for the mix of different efficiency levels in streetlighting technologies. At present, about 20% of all street lights are of the high efficiency sodium vapour (high and low pressure) variety while the rest are lower efficiency bulbs (either mercury vapour, fluorescent or incandescent). By the end of the forecast period it is expected that more than 70% of all bulbs will be sodium vapour with the remainder being predominantly mercury vapour. The large shift towards efficient street lighting systems means that street lighting demand will grow only slightly from the current level of 740 GW.h to just over 800 GW.h by 2015. The growth that does

occur is derived from the effect of increases in housing stock on the number of miles of streets.

The remainder of the non-building related sub-sector is also tied to the growth in housing stock. The resulting forecast for growth of total non-building related electricity demand is roughly 1.5% per year.

The composition of final demand for electricity in the commercial sector by end use is given in Figure 4.1.2.1. The forecast, by building type, is given in Table 4.1.2.2 and by end use, in Table 4.1.2.3.

4.1.3 Industrial Sector

The industrial sector end-use forecast covers the resource, construction and manufacturing sectors. This year the forecasts for four industries (cement, iron and steel, industrial chemical and pulp and paper) were produced using a series of new industry-specific models. These models were developed by the Load Forecasts Department using EPRI's INDEPTH modelling framework. The four industries accounted for 48% of total industrial electricity demand in 1988, 57% of total industrial energy demand. Forecasts for the remaining industries were produced using the industrial sector of the existing end-use model (EUM) as in previous years.

INDEPTH provides a flexible framework for load forecasting and the analysis of demand side management programs, allowing the analyst to include much greater detail than is possible in the EUM. Each industry is defined in terms of a number of processes, each process having various competing technologies available to accomplish the task at hand. Technologies are selected on the basis of minimum life cycle cost, unlike the EUM which relies strictly on the analyst's judgement. This approach requires that the capital cost, operating cost and energy consumption be specified for each technology as well as various financial parameters such as the discount rate. Data for each industry were gathered by a consultant familiar with the industry. The analyst is able to test the sensitivity of the most-likely forecast by running the model using different input assumptions (e.g. future energy prices). Forecasts of the main products of each industry in physical units are produced by the Economic Forecasts section. Due to different physical unit forecasts and base years, it is not possible to estimate precisely the net impact of the new INDEPTH models on the load forecast by comparing this year's INDEPTH forecasts with last year's EUM forecasts. In general, however, no major changes in electricity intensity occurred in any industry, largely due to the fact that much of the information gathered for use in the INDEPTH models was incorporated in last year's forecast.

In order to remain competitive, industry is driven to minimize costs while continuing to improve product quality. Another factor of increasing importance is stricter environmental regulation. The implications for electricity demand of these pressures are not immediately obvious. In certain industries, especially those with electricity-intensive production processes, concerted efforts have been made to reduce electricity demand per unit output with some success. New membrane cell chlor-alkali plants use substantially less electricity than older diaphragm cell plants, for example. In other industries, however, efforts to reduce costs, increase productivity, reduce emissions and/or improve product quality have led to increased electricity use per unit output. A number of examples are cited in the following section. End-Use models provide a consistent framework to evaluate the impact of these changes on total electricity demand.

The electricity intensity of the Ontario industrial sector, as defined by the ratio of electricity demand to industrial GDP, is shown in Figure 4.1.3.1. No

clear trend is evident over the period 1961 to 1988, although it has declined significantly during the 1980s. Based on the Ontario Hydro forecast of industrial GDP and the industrial end-use electricity forecast, this ratio is projected to trend slightly lower over the forecast period.

The growth rates of electricity demand for the eight major electricity-using industries are shown in Table 4.1.3.1 for selected intervals.

Figure 4.1.3.1

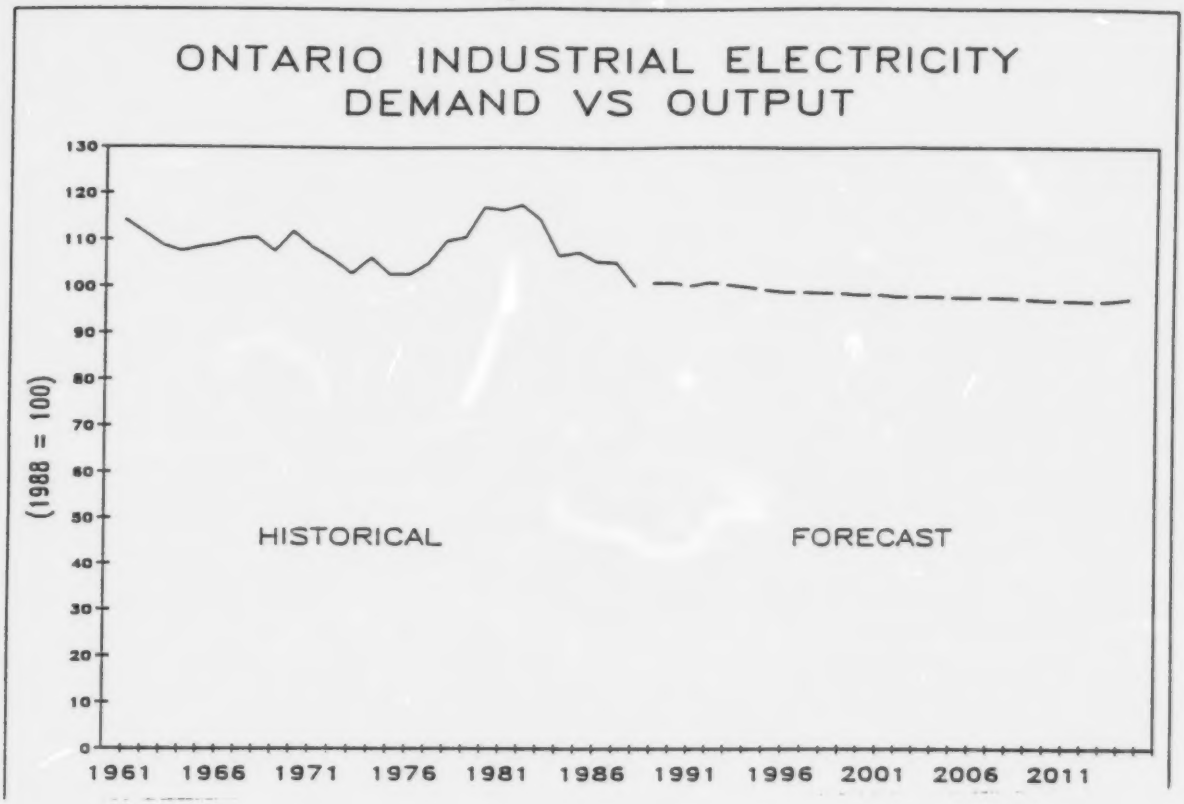


Figure 4.1.3.2

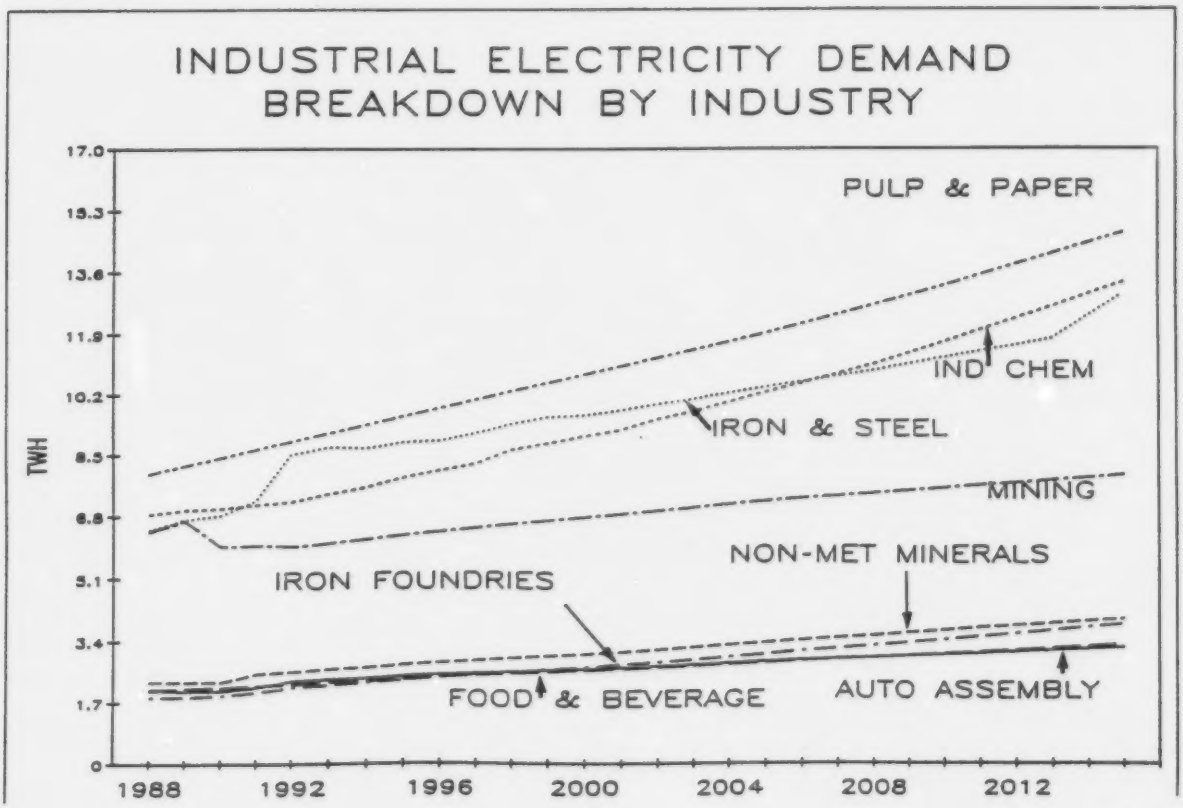


Table 4.1.3.1

Industrial Electricity Demand Forecasts

	Average Growth Per Year	
	1988-2000	2000-2015
	%	%
Automobile Assembly	2.1	1.4
Food and Beverage	1.9	1.7
Industrial Chemicals	2.3	2.6
Iron Foundries and Automotive Parts	3.2	2.5
Primary Iron and Steel	3.4	2.0
Mining, Milling, Smelting and Refining	0.5	1.1
Non-Metallic Minerals	2.5	1.9
Pulp and Paper	2.5	2.1
Other Industries	3.1	2.6
Total Industrial Sector	2.5	2.1

The accompanying rationale for each industry is summarized below:

Automobile Assembly (SIC 325): Vehicle production is forecast to grow at an average rate of 2.4% to the year 2000, 1.6% over the period 2000-2015. The electricity demand per vehicle is expected to decline slightly, resulting in forecasted electricity demand growth averaging 2.1% from 1988-2000 and 1.4% from 2000-2015. Electricity demand for lighting and HVAC, currently estimated to account for 34% of total demand, is expected to drop substantially as a result of both improved equipment efficiencies and reduced floor area per vehicle produced. The latter trend is expected due to improvements in supplier-assembler coordination (e.g., Just-In-Time inventory systems), flexible assembly lines and increased automation. This downward trend in electricity intensity is expected to be partially offset by increased use of electric heat treatment equipment.

Food and Beverage (SIC 10, 11): Output is expected to grow at an average rate of 1.7% and 1.6% over the 1988-2000 and 2000-2015 periods, respectively. Overall a slight increase in electric intensity is expected due mainly to the increased penetration of a variety of electrotechnologies. In particular, the use of freeze concentration in the beverage industry (used for separation) is expected to increase dramatically. Other electrotechnologies expected to add to electricity demand include microwave heating (for dehydration), membrane technologies (for evaporation and separation) and heat pumps (for separation). Counteracting the trend toward increased electricity use will be efficiency improvements expected to occur in refrigeration technologies. Resulting growth in electricity demand is forecast at 1.9% to 2000 and 1.7% from 2000-2015.

Industrial Chemicals (SIC 371, 3721): The INDEPTH model of the industrial chemicals industry is driven by the production of seven key chemicals. Product growth rates are forecast as follows:

Table 4.1.3.2

	1988-2000 %	2000-2015 %
Ammonia	1.1	1.3
Chlorine/Caustic Soda	1.7	1.6
Ethylene	4.1	5.2
Nitrogen	1.8	1.6
Oxygen	1.2	0.9
Sodium Chlorate	2.3	2.1
Other	2.7	2.7

New membrane cells are expected to replace diaphragm and mercury cells for chlorine/caustic soda production leading to reduced electricity demand. No major technology shifts are foreseen for sodium chlorate or industrial gas (oxygen and nitrogen) production although continuing efforts to improve efficiency will result in some savings. The production of petrochemicals (including ammonia and ethylene) is expected to become more electricity-intensive as steam turbine motor drives are replaced in favour of electric motor drives. The adoption of electro-organic processes for the production of petrochemicals is very unlikely, however, without a substantial increase in the price of fossil fuel feedstocks. Growth in the demand for electricity is forecast for the industry as a whole at 2.4% to 2000 and 2.6% from 2000 to 2015.

Iron Foundries and Automotive Parts (SIC 294, 325): Production of iron castings is forecast to grow at an average rate of 2.2% to 2000 and at 1.9% from 2000-2015. Electric melting furnaces are expected to continue replacing older coke-fired cupola furnaces due to their improved productivity, temperature control and reduced emissions. Metal heat treating with electric resistance and induction heaters is also expected to increase at the expense of natural gas-fired equipment. Advances in process control technology should improve the efficiency of electric furnaces, however. The overall growth in electricity demand is forecasted to be 3.2% to 2000 and 2.5% from 2000-2015.

Primary Iron and Steel (SIC 291): The INDEPTH model which has been developed for the iron and steel industry is driven by the demand for ten key finished and semifinished steel products rather than just simply the production of raw steel. Forecast growth rates to the year 2000 vary from a low of -6.9% for ingots to a high of 6.6% for cold-rolled sheet and strip. In general, more highly finished (and more electricity-intensive) products such as cold-rolled and galvanized sheet and strip are expected to grow most quickly due to demand for higher quality steel, in particular by the automotive industry. The overall growth in steel product demand in this period is 2.3%. From 2000 to 2015, steel product demand is forecast at 1.4%. The additional steelmaking capacity needed to meet this increased demand will likely use electric arc furnaces, given the substantial capital and operating cost advantages of this technology and the relatively large supply of scrap steel which is available to feed them. The percentage of steel product in Ontario from electric arc furnaces is thus forecast to rise from 15% today to just under 30% by the year 2000, reaching 40% by 2015.

Other technological developments which will increase the demand for electricity include electric ladle preheaters and furnaces. The latter are used to improve steel quality as well as acting as a buffer between steelmaking and casting operations. Induction edge reheaters, used in conjunction with direct rolling of steel, will also increase load.

A number of measures are expected to reduce electricity use as well. Electric arc furnaces today are approximately 20% more efficient than a decade ago, as well as being more productive, due to a variety of technologies and operating practices. This trend towards greater efficiency and higher productivity is expected to continue. By casting much closer to the final product shape, "near-net-shape" continuous casters reduce the amount of rolling required and thus hold the potential to reduce electricity use substantially. This technology is currently undergoing intensive development throughout the world, including Canada, due mainly to the potential for a large capital cost reduction compared to current equipment. Growth in electricity demand for the industry is forecast at 3.4% to 2000 and 2.0% from 2000 to 2015.

Mining, Milling, Smelting and Refining (SIC 06, 07, 08, 09, 295): Growth in production to 2000 is forecast at 1.0% for nickel, 0.9% for copper, 0.7% for zinc and -0.2% for other minerals. From 2000 to 2015, growth is forecast at 0.5% for nickel, 0.4% for copper and zinc and 0.9% for other minerals. The trend away from diesel Load-Haul-Dump (LHD) machines to electric LHD's is expected to continue given the latter's superior productivity, reduced operating costs and improved environmental quality. In general, stricter environmental regulations will also lead to an increase in electricity use. The change to oxygen flash smelting of nickel at Inco falls into this category. Some savings are expected, however, in fan and pump applications due to the use of variable speed drives. Electricity use for the industry as a whole is forecast to increase at a rate of 0.5% to 2000 and 1.1% from 2000 to 2015.

Non-Metallic Minerals (SIC 351, 352, 356, 357, 358): Product growth forecasts are as follows:

Table 4.1.3.1

	1988-2000 %	2000-2015 %
Abrasives - Silicon Carbide	1.0	0.9
- Aluminum Oxide	1.7	1.6
Cement	3.2	2.4
Clay	0.3	0.9
Glass	2.8	2.6
Lime	2.0	1.8

In the very electricity-intensive abrasives industry, limited opportunities for efficiency improvements are available given the strong efforts of the industry to date. In the glass industry, the use of electric boost in gas-fired glass furnaces is expected to continue to increase given the productivity improvements possible with this technology. Only minor changes are expected in the production of clay and lime. The electricity intensity of cement production is expected to increase slightly due to the replacement of older wet kiln capacity with modern dry kilns. Although substantially more energy efficient overall, new dry kilns require electricity for their preheaters and precalciners. Some electricity savings in the cement industry are expected as a result of improved grinding mills and particle separators.

Overall, electricity use is forecast to grow at 2.5% to 2000 and 1.9% from 2000 to 2015.

Pulp and Paper (SIC 271, 251): Product growth rates are as follows:

Table 4.1.3.4

	1988-2000 %	2000-2015 %
Newsprint	0.6	0.5
Paperboard	2.7	2.5
Wrapping Paper	0.2	0.1
Fine (Writing) Paper	3.5	3.1
Export Pulp	1.4	1.0
Tissue and Building Paper	2.3	2.2

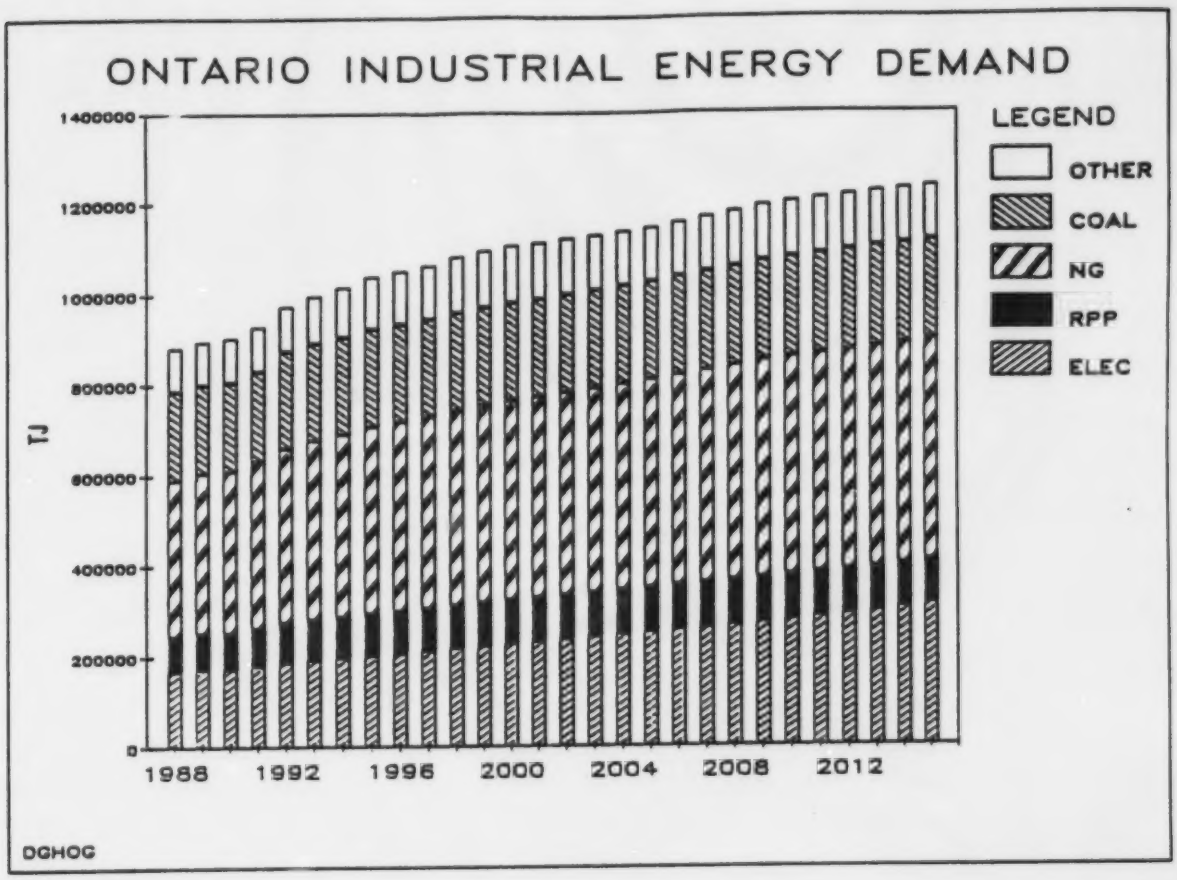
The pulp and paper forecast was performed using an INDEPTH linear programming model.

Thermo-mechanical pulp (TMP), currently produced at three Ontario mills, is expected to account for over 50% of the content of newsprint by 2000 (up from 12% at present) and reach 100% by 2010. Newsprint made from TMP is regarded more favourably than newsprint produced from groundwood (currently the majority) due to its predictable quality and improved ability to reproduce colour photographs and graphics. Although its overall cost of production is lower than groundwood, TMP requires approximately 35% more electricity. TMP is also expected to be used in fine paper, reaching a share of 40% by 2010, up from 0% at present. Chlorine dioxide bleaching of pulp is expected to begin replacing chlorine bleaching due to its reduced environmental impact and lower energy requirements. Little change is expected in papermaking technology. Electricity use is forecast to grow at 2.5% from 1988-2000 and 2.1% from 2000 to 2015.

Increasing political pressure to use recycled fibre, especially in the production of newsprint, was not explicitly considered in this forecast. The contribution of recycled fibre was forecast to remain at essentially current levels. The analysis of the impact of such pressure would have to consider two factors: (1) effect on electricity intensity of changes in technology mix, and (2) decreased virgin newsprint demand.

Other Industries: This category includes rubber and plastic (4.2% growth in electricity demand from 1988 to 2015), textiles and clothing (1.6%), metal fabrication (3.4%), electrical and electronic (3.7%) and chemical products (3.4%). Output growth in most of these industries is quite strong. In general, the concern with electricity costs and efficiency in these industries is low given the minor share which electricity composes of total production costs. Lighting and HVAC, relatively important end-uses in these industries, are expected to experience some improvement in efficiency. This will likely be more than made up for by the increased penetration of a variety of electrotechnologies, however.

Figure 4.1.3.3



Other Fuels: Growth in demand for refined petroleum products, natural gas, coal and other fuels (natural gas liquids, steam and hog fuel) is projected at 0.8%, 1.3%, 0.4% and 0.8%, respectively, over the 1988-2015 period (see Figure 4.1.3.3). Total energy demand, including electricity, is forecast to increase at 1.3% over the same period. Despite recent large increases in the demand for natural gas, in particular, continuing efforts to improve efficiency are expected to slow growth for all fuels in the long term as real energy prices increase. New industrial processes, improved process control and energy monitoring systems will all play a role. Natural gas is expected to continue to be the fuel of choice for most new fossil-fuel fired equipment. Coal use is determined primarily by the fate of steelmaking from iron ore, a technology which is expected to grow only marginally.

4.1.4 Transportation Sector

The transportation sector, although a large consumer of energy, accounts for under 0.5% of total electricity demand. Roughly 2/3 of this is electricity use in the road transport and urban transit segment which is composed of the energy requirements of subways, streetcars and trolley buses. Recognizing the greater efforts made by the Ministry of Energy to study this sector, Ontario Hydro has directly incorporated the MOE's estimated annual growth of 2.1% into this year's forecast.

Pipelines, an even smaller component, constitutes the remainder of the Transportation Sector and is incorporated under the 'Other' category.

4.1.5 Agricultural Sector

Electricity use by the agricultural sector is comprised of two components:

(1) residential use by farming households,
(2) operational use in running farming equipment.

Ontario Hydro aggregates the first component into the Residential Sector. The remainder is referred to as the Agricultural Sector and is incorporated in Table 4.1.6. under the 'other' category.

Dairy and hog farm operations are the principal drivers for this sector, followed by poultry and grain production. Grain production is forecasted to have the strongest annual output growth rate at approximately 4%, while the remaining drivers are expected to show more modest growth of about 1.5% per year.

The agricultural sector currently accounts for about 0.7% of total electricity demand and is forecast to have a 2% annual growth rate over the forecast horizon.

4.1.6 The 1989 End-Use Forecast

The final demand for electricity by sector is given below. To transform the total Ontario demand estimates produced by the end-use models into Ontario Hydro Basic Electricity demand, a number of adjustments are carried out. The main contributors to this adjustment are natural load displacement generation and transmission and distribution losses. In addition, electricity not sold by Ontario Hydro and residual statistical differences are taken into account.

The strongest growth, particularly in the short term, is expected to come from the commercial sector. The commercial sector's share of the electricity market will increase from a 1988 level of 35% to a 2015 level of 37%. This will basically come at the expense of the residential sector which is expected to show a decrease in share of 2.5 percentage points. Industrial will maintain its 36% share over the forecast period.

Table 4.1.6

End-Use Forecast (TW.h)

Year	Residential	Commercial	Industrial	Transportation*	Other**	Total
1988 (A)	36.5	45.1	47.0	0.4	1.1	130.0
1989	37.5	48.2	48.3	0.4	1.1	135.5
1990	38.6	50.1	48.3	0.4	1.1	138.4
1995	45.3	60.5	56.4	0.4	1.2	163.9
2000	49.7	67.8	63.2	0.5	1.4	182.6
2005	53.7	75.4	69.9	0.5	1.5	201.0
2010	56.9	82.7	77.5	0.6	1.6	219.3
2015	61.6	89.9	86.8	0.6	1.8	240.8
Growth Rates						
1988-1995	3.1	4.3	2.6			3.4
1988-2000	2.6	3.5	2.5			2.9
1988-2010	2.0	2.8	2.3			2.4
1988-2015	2.0	2.6	2.3			2.3
1995-2015	1.5	2.0	2.2			1.9

Year	Total	Load Displacement	T&D Losses	Adjustment***	Basic Electricity Demand
1988 (A)	130.0	5.5	10.6	0.7	134.4
1989	135.5	5.9	11.0	1.7	138.8
1990	138.4	6.2	11.0	1.7	141.5
1995	163.9	6.9	12.6	2.1	167.6
2000	182.6	7.6	14.1	2.3	186.8
2005	201.0	8.3	15.5	2.5	205.7
2010	219.3	8.9	17.0	2.8	224.6
2015	240.8	9.5	18.6	3.0	246.8
Growth Rates					
1988-1995					3.2
1988-2000					2.8
1988-2010					2.4
1988-2015					2.3
1995-2015					2.0

* Road Transport and Urban Transit
** Pipelines; Agricultural Operations
*** Ontario Electricity not sold by Ontario Hydro; Statistical differences

4.2 Econometric Energy Model of Ontario - EEMO

EEMO is a sectoral econometric model. The relationships between energy consumption and the variables which determine the level of this consumption have been estimated for the period 1962 to 1988. EEMO forecasts the level of energy consumption for Ontario as a whole by individual fuel -- electricity, natural gas, oil and coal -- and by consuming sector -- residential, commercial and industrial. The major factors which influence the level of energy consumption are fuel prices and scale factors, such as the number of households and the level of aggregate economic activity.

The evolution of EEMO from its predecessor (EDEM) was described in last year's load forecast report (LF881212). During 1989 further development of the model was carried out as part of the Department's ongoing econometric programme.

In earlier versions of the model total energy demand in the manufacturing, mining and commercial sectors was estimated by analysing the difference between actual energy consumption in each sector and energy consumption based on the assumption of fixed technology. The latter was derived using the 1971 Input-Output model for Canada. In recent years, however, the Economic Forecasts Section has produced forecasts of industrial output using the 1979 Input-Output model for Ontario. These are used in the End-Use model forecast. In order to take advantage of these industrial output forecasts and to put the drivers of the two long-term modelling approaches on a consistent footing it was decided to re-estimate the industrial and commercial econometric total energy demand models. Also, actual energy consumption, rather than the difference mentioned earlier, has become the dependant variable in the equations. At the same time the manufacturing and mining sectors were combined into a single set of equations.

The second major change in the model was the adoption of the Market Reference Dataset produced by the Energy Management Branch as the dataset to be used in the estimation of all the energy equations of the model. Since the sectoral definitions used in this dataset are different from those used previously there were some minor adjustments necessary to the historical data series. As a result the sectoral forecasts are not strictly comparable to those produced last year. Also, because of the way Statistics Canada energy data have been collected, the agricultural sector is included in the residential sector in EEMO.

EEMO produces energy forecasts to 2015. The economic forecasts used by the model are from the 1989 Long-Term Economic Outlook. The electricity demand forecast is tuned to the latest Short-Term Forecast.

An important determinant of growth in the long-term economic forecasting model is the demographic forecast for Ontario. The downward trend in Ontario GDP growth rates and the corresponding trend in long-term load growth may be explained in part by the declining growth rates forecast for Ontario's labour force.

4.2.1 Residential Sector

The residential demand for electricity is modelled by considering separately: (a) the demand for energy-using appliances (saturation), and (b) the intensity of use of the appliance stock (usage). Two indexes have been developed to reflect those concepts. They consider 13 major appliance types including electric space heating and water heating.

The aggregate saturation index (ELSAT) is defined as:

$$ELSAT_t = \frac{\sum_{i=1}^{13} USE71_i \times SATi_t}{\sum_{i=1}^{13} USE71_i \times SATi_{71}}$$

where: $USE71_i$ is the 1971 kW.h usage for appliance i
$SATi_t$ is the proportion of households with appliance i in year t

The aggregate use index (ELUSE) is defined as:

$$ELUSE_t = \frac{ELRES_t}{\sum_{i=1}^{13} USE71_i \times SATi_t}$$

where: ELRESTt is electricity consumption per household in year t

The estimated equation for ELSAT is a partial adjustment model of the prices of electricity, natural gas and income per household. The aggregate use index (ELUSE) is also estimated in partial adjustment form with the price of electricity and income per household as explanatory variables. Also included in this equation are a time trend and cooling degree days. The elasticities are shown in the following table.[1]

Table 4.2.1.1: Estimated Price and Income Elasticities in the Residential Sector

	ELSAT		ELUSE	
	Short-Run	Long-Run	Short-Run	Long-Run
Price of Electricity	-0.15	-0.57	-0.16	-0.22
Price of Natural Gas	0.07	0.28	N/A	N/A
Income per Household	0.27	1.04	0.46	0.62

The use index was increasing over the period 1962 to 1972 - an era of falling or fairly constant real electricity prices and increasing real income per household. From 1973 to 1987 when real electricity prices were rising and there was a strong push towards energy conservation, the use index gradually declined at an average annual rate of 0.7% to a level of 97.9 (1980=100). In 1988 total residential electricity consumption increased by 8%; the largest year-over-year change in the period since 1962. As a result of this and the fact that the saturation of electricity-using appliances did not increase proportionately the use index rose considerably in 1988 as shown in Table 5.1.2. In the econometric model, however, this does not interfere with the overall trend with the result that over the forecast period to 2015 a continued decline is projected, at a rate of about 0.6% per year.

The aggregate saturation index has grown over the entire historical period. Three distinct phases may be identified:

[1] Similar indexes for aggregate appliance saturation and usage are also estimated for natural gas and fuel oil.

1. fairly steady growth from 1962 to 1972, corresponding to the period of declining or constant real electricity prices and increasing incomes;

2. faster growth from 1973 to 1978, reflecting the increasing substitution into electricity and the drop in electricity prices relative to oil; and

3. slower growth rates for the period 1979 to 1988, due to low growth in income per household (as a result of the 1982 recession), and average positive growth for electricity prices relative to natural gas.

This index is forecast to continue to grow until 2015 at an average rate of 1.4% per annum, as favourable electricity prices and steady income growth are projected.

Forecasts of the saturation and use indices and the resulting forecast of residential electricity consumption are given in the table below:

Table 4.2.1.2: Residential Electricity Forecast

Year	ELAST*	ELUSE*	Electricity (GW.h)	Total Residential Energy (GW.h)	Market Share (%)
1988	112.7	105.0	37,447	118,212	31.7
1990	114.5	104.0	39,703	124,115	32.0
2000	129.3	101.2	51,427	138,689	37.1
2015	162.4	89.1	66,291	148,666	44.6

*1980 = 100

The combined effect of the forecasts of the saturation and use indices is that residential electricity consumption grows over the forecast period at an annual average rate of 2.1%. However, the pattern of growth is not uniform over the period. Between 1989 and 2000 residential electricity consumption increases at an average rate of 2.7% as increasing saturation more than compensates for the decline in aggregate usage. From 2000 to 2015, however, the growth of ELSAT is more than offset by a more rapid decrease in ELUSE with the result that overall electricity consumption increases at an annual rate of 1.7% during the last fifteen years of the forecast. Total residential energy is forecast to grow much more slowly than electricity due primarily to steady increases in the real prices of oil and natural gas. As a result, the market share of electricity in the residential sector shows an increasing trend - from 31.7% in 1988 to 44.6% by 2015.

4.2.2 Industrial Sector

The demand for electricity in the industrial sector is estimated in a two-stage procedure. In the first stage a total energy equation of the error-correction type is estimated in log form as a function of industrial GDP and its lagged value, the price of energy and a lagged dependant variable. Implicit in the model is the assumption of constant returns to scale with respect to GDP. This assumption was tested and the null hypothesis was not rejected.[2] Therefore, the long-run energy elasticity with respect to GDP is 1, while the short-run value is estimated to be 0.74. The own-price elasticity of total energy is estimated to be -0.05.

[2] When the assumption of constant returns to scale is relaxed the estimated own-price elasticity of demand for total energy has the wrong sign.

In the second stage, a linear logit cost share model calculates the cost-minimising mix of fuel shares for four fuels - electricity, oil, natural gas and coal. The cost share of a particular fuel is its share of total expenditure on all forms of energy by industry; it is, therefore dependent on both fuel prices and actual energy consumption. On the other hand the market, or quantity, share of a fuel is the ratio of its consumption to total energy use. Therefore, depending on the relative movements of fuel prices and the consumption of different fuels it is quite possible to have cost shares and market shares moving in different directions.

The linear logit formulation imposes global concavity on the estimated function consequently eliminating the possibility of having negative cost shares in the out-of-sample simulation. Unlike the translog formulation, the linear logit specification ensures non-negativity for all data points although symmetry of the cross-price elasticities holds only at the historical mean of the cost shares. In this sense, global symmetry is sacrificed for global concavity. In forecasting, this trade-off is worthwhile because wrong signs on own-price elasticities and/or negative share predictions are very implausible. The long-run elasticities for the industrial sector are shown in the following table:

Table 4.2.2.1 Estimated Total Long-Run Elasticities in the Industrial Sector

	Electricity	Natural Gas	Oil	Coal	Total Energy
Price of Electricity	-0.46	-0.14	0.13	0.25	0.21
Price of Natural Gas	0.05	-0.55	0.26	0.20	-0.28
Price of Oil	0.05	-0.02	-0.97	0.12	-0.03
Price of Coal	-0.20	0.15	0.02	-0.63	-0.04

The elasticities shown in Table 4.2.2.1 should be interpreted while keeping in mind that they are elasticities on the cost shares of the individual fuels and, as mentioned above, the cost share of a fuel is a function of both its price and its level of consumption. The signs of the estimated elasticities reflect the combined movements of these two quantities over the period of estimation. The elasticities in Table 4.2.2.1 show the combined impact on the demand for each fuel of both of these effects. The pure effect of relative prices - the "energy-neutral" elasticity - can be derived from Table 4.2.2.1 by subtracting the total energy elasticity from the elasticity of the individual fuels.

For the forecast period, the price of electricity relative to the prices of oil and natural gas is projected to decline at an annual average rate of about 1.6%. The cost share of electricity declines gradually from 48.7% in 1988 to 40.8% by 2015. However, its market (quantity) share is relatively stable - moving from 21.5% in 1988 to only 22.9% by 2015. Over the same period the market shares of oil and coal continue their historical decline and the resulting displaced energy is picked up by natural gas.

Table 4.2.2.2 Market Share of Electricity in the Industrial Sector

Year	Electricity (TW.h)	Growth Rate* (%)	Energy (TW.h)	Growth Rate* (%)	Market Share (%)	Cost Share (%)
1988	47.0	-	218.3	-	21.5	48.7
1990	47.5	-	227.0	-	20.9	48.1
1995	57.4	3.83	267.4	3.33	21.4	47.8
2000	68.6	3.66	298.5	2.23	23.0	45.5
2005	75.8	2.00	327.2	1.85	23.2	44.3
2010	82.6	1.73	356.8	1.75	23.1	42.6
2015	88.8	1.47	387.2	1.65	22.9	40.8

* Average annual percentage change for five-year periods

4.2.3 Commercial Sector

The commercial sector is modelled much like the industrial sector in that the cost shares are estimated using a linear-logit formulation. However, in this sector there are only three fuels - electricity, oil and natural gas. The total energy equation is a partial adjustment model estimated in log linear form. The assumption of constant returns to scale with respect to commercial GDP is relaxed. The short-run and long-run elasticities of energy with respect to GDP are estimated to be 0.19 and 1.18 respectively. Long-run total elasticities are shown in the following tables:

Table 4.2.3.1 Estimated Total Long-Run Elasticities in the Commercial Sector

	Electricity	Natural Gas	Oil	Total Energy
Price of Electricity	-0.97	-0.70	-0.18	-0.82
Price of Natural Gas	-0.28	-0.68	-0.11	-0.46
Price of Oil	-0.03	0.09	-0.99	0.00

The comments made earlier about the nature of cost share elasticities also apply here. In addition there are some anomalies in the commercial sector energy data used to estimate the model. For example, the official data show commercial natural gas consumption declining during the period since 1983 at a time when real natural gas prices were also falling. This may account for somewhat surprising cross-price elasticity with electricity which is given in Table 4.2.3.1.

Although electricity's price competitiveness is improving steadily over the forecast period its cost share is virtually unchanged. However, these same price effects increase electricity's market (quantity) share as is shown in the following table:

Table 4.2.3.2 Market Share of Electricity in the Commercial Sector

Year	Electricity (TW.h)	Growth Rate* (%)	Energy (TW.h)	Growth Rate* (%)	Market Share (%)	Cost Share (%)
1988	45.0	-	104.1	-	43.2	71.2
1990	48.3	-	113.7	-	42.5	71.6
1995	62.1	5.15	138.3	3.99	44.9	72.9
2000	72.4	3.11	155.4	2.36	46.6	70.9
2005	81.2	2.30	172.7	2.13	47.0	70.3
2010	91.7	2.48	192.1	2.15	47.7	69.9
2015	104.7	2.69	210.7	1.87	49.7	70.6

*Average annual percentage change for five-year periods

4.2.4 The 1989 EEMO Forecast

The EEMO forecast results project that total residential electricity use will increase at a compound rate of 2.1% over the period 1989 to 2015 - about .5 percentage points less than the growth rate of total electricity demand. In fact, the rate of growth of residential demand follows a downward trend from the late 1990's on, due to the slow down in population growth resulting in a decline in the rate of growth of household formation from 1.6% a year between 1989 and 2000 to an average of slightly over 1% a year for the last fifteen years of the forecast. In addition there is a slowing down of the growth rate of personal income after 2000 from 2.8% to 2% a year. These factors weaken the impact of the increase in the growth rate of aggregate saturation (ELSAT) over the 2000 to 2015 period and, together with the increase in the rate of decline of aggregate usage (ELUSE), cause the decrease in the growth rate of residential electricity consumption.

The commercial sector has faster growth rates for both total energy and electricity than the residential sector. Its electricity growth averages 3.2% a year for the period 1989 to 2015. Commercial electricity consumption also grows faster than the output of the commercial sector which is forecast to increase at an average annual rate of 2.3% between 1989 and 2015. Electricity's share of the commercial market grows from 43.3% in 1988 to 49.7% in 2015.

In the industrial sector electricity growth averages about 2.4% a year between 1989 and 2015, while total energy grows slightly more slowly, and industrial output growth averages 2.3% a year.

In order to derive the Basic Load Forecast from the sum of the three sectoral forecasts, load displacement non-utility generation and non-Hydro electricity sales are subtracted out and other adjustments, mainly line losses, are added on. Compared to the 1988 forecast the level of non-utility generation has been increased and the imputed level of non-Hydro sales has been reduced resulting in the observed increase in the level of the 'adjustments'. The load displacement that is expected as a result of normal market forces is described in the section on incentive-driven load displacement generation.

Table 4.2.4 EEMO 1989 Forecast

Year	Residential (TW.h)	Commercial (TW.h)	Industrial (TW.h)	Own Generation TW.h	Adjustments* TW.h	EEMO Basic Electric Energy TW.h
1988(A)	37.5	45.0	47.0	5.5	10.4	134.4
1995	45.4	62.1	57.4	6.9	10.7	169.1
2000	51.4	72.4	68.6	7.6	12.5	197.8
2005	57.1	81.2	75.8	8.3	13.9	220.2
2010	61.8	91.7	82.6	8.9	15.4	243.1
2015	66.3	104.7	88.8	9.5	16.9	267.9
Growth Rates (Annual Average Percent Change)						
1988-1995	2.8	4.7	2.9			3.3
1988-2000	2.7	4.0	3.2			3.3
1988-2010	2.3	3.3	2.6			2.7
1988-2015	2.1	3.2	2.4			2.6
1995-2015	1.9	2.6	2.2			2.3

*Ontario Hydro losses less Ontario electricity not sold by Hydro (excluding own generation)

5.0 LOAD IMPACT OF INCENTIVE-DRIVEN DEMAND MANAGEMENT AND LOAD DISPLACEMENT

5.1 Introduction

The end-use, econometric and recommended forecasts described earlier in this section are all 'Basic' forecasts of load in Ontario. That is, they are projections of the load that Ontario Hydro would expect to serve as a result of market forces where there are no interventions by Ontario Hydro in the form of incentives. The Primary load Forecast is derived by subtracting from the 'Basic' Load Forecast the net load impact of incentive-driven demand management and load displacement generation.

Ontario Hydro's incentive programs for demand management include both changes in rate structure to achieve load-shifting, such as time-of-use rates, and financial incentives for electrical efficiency improvement to reduce load, such as grants or attractive loans. Some of Hydro's programs provide valuable information such as audits and consulting studies specifically to customers. These may also contribute to the net reduction in load without a direct transfer of financial assistance. The estimated net impact of such programs is included in this forecast.

Ontario Hydro's incentive programs for load displacement generation provide financial assistance to industries wishing to produce electricity for their own consumption, thereby reducing the load Ontario Hydro is required to serve.

It is the Primary Load Forecast minus capacity interruptible loads which determines the Firm Load Forecast used by System Planning.

5.2 Incentive-Driven Demand Management

The net load impact estimates for incentive-driven demand management programs offered by Ontario Hydro consist of the load reduction due to electrical efficiency improvements and load shifting. In preparing the forecast, the most recent information was reviewed for both types of programs.

The short-term (1989-1994) estimates of electrical efficiency improvements are based on a review of the estimates contained in the 1989 Energy Management Branch Business Plan and extensive discussions with representatives from Energy Management Branch. The longer term estimates for 1995 and beyond are based on recent in-depth analysis of electrical efficiency improvement potential undertaken by the Energy Economics Section of the Economics and Forecasts Division for input into the 1989 Demand/Supply Plan. The analysis takes into account the findings of research reports commissioned by the Energy Management Branch, the avoided costs of efficiency improvement measures provided by System Planning, as well as the penetration rate estimates provided by program experts of Energy Management Branch.

The estimates of the impact of load shifting programs in the short term (1989-1994) are based on information incorporated in the Energy Management Branch Business Plan as well as the results of a questionnaire on the impact of time-of-use rates distributed to customers. The results of several Ontario Hydro studies which investigate time-of-use rates and the implementation experience of other utilities were used as a basis for the long-term estimates. Further research is planned to assess the response of customers who face time-of-use rates.

The forecast does not yet have associated with it an uncertainty range. It can be said to contribute to the total uncertainty in the load forecast.

5.2.1 Electrical Efficiency Improvement Programs

Over the past year, Ontario Hydro has made considerable progress in planning various demand management initiatives. A number of electrical efficiency improvement programs have already been launched in 1989 and more programs will be approved by senior management over the coming months. The following provides a detailed description of these programs and the technologies considered in the long-term analysis on a sector by sector basis.

5.2.1.1 Program Description by Sector

Residential Sector

Major electrical efficiency improvement programs currently underway or in an advanced stage of planning in the residential sector are directed at the following:

- R-2000 Houses
- Ground Source Heat Pumps
- House Renovations
- Water Heating
- Energy-Efficient Appliances
- Agricultural Uses

The R-2000 program has already received approval to offer a $2,000 incentive to home buyers to be applied against the incremental construction cost of an R-2000 home. As well, a $500 incentive is available for builders to cover additional administrative costs. The incentives offered are approximately $667 per KW saved and are expected to yield about 3 KW of savings per house.

The Ground Source Heat Pump program in the Existing Housing Segment is expected to get approval sometime later this fall. A similar program is also expected to be offered in the New Housing Segment. On average, a ground source heat pump will save about 4 KW on peak demand where it replaces an electric resistance heating system which is operating on peak.

The Renovation program will cover a number of technologies, including window replacements, energy-efficient doors, basement insulation and other thermal envelope improvement upgrades. Homeowners will be offered financial incentives to install these energy efficient measures.

With respect to electric water heating systems, water heater tank wraps and energy-efficient (flow restricting) showerheads will be promoted in the coming months. In 1989, several pilot projects were tested for water heater blankets and showerheads and customer response was very positive. Homeowners with electric water heating will be offered the energy-efficient blankets free of charge along with a discount coupon promotion for the flow restricting showerheads.

The Energy-Efficient Appliances program will offer incentives to homeowners to purchase more energy-efficient appliances such as refrigerators, freezers, clothes washers and dish washers.

Several incentive-driven programs are also planned for the Agriculture Segment. These include high efficiency heat lamps, heat/vent interlock controls, and heater sizing. In addition, a conversion program of sentinel lights from mercury vapour to high pressure sodium will be offered.

A Residential Energy Audit Program (RECAP) is expected to be launched soon to help homeowners identify opportunities for electrical efficiency improvement

measures. Although this program will be more information-related, it will direct customers to follow-up other incentive-driven programs offered by Ontario Hydro.

For the long-term analysis, the technologies considered in the residential sector can be divided into four categories: thermal envelope improvements in existing houses, new housing thermal envelope upgrades, heating system improvements, energy efficient appliances and other measures. Existing house thermal envelope improvements include various insulation upgrades (roof, attic, wall, and floor), infiltration improvements and door and window improvements. New housing thermal envelope improvements are captured through upgrading new electrically heated Ontario Building Code (OBC) houses to the R-2000 standard. Although upgrades of OBC houses to levels less than R-2000 are also desirable, OBC to R-2000 is used in the analysis since it represents the highest economic potential and is least difficult to measure. Heating system improvements refer to the replacement of existing electric furnaces with a heat pump system. Other measures include conversions to energy efficient electric appliances, electric domestic water heater improvements and high efficiency lighting.

Commercial Sector

A number of programs offering financial incentives for electrical efficiency improvements were developed for commercial sector customers in 1989. These programs include:

- Energy Efficient Lighting
- Savings-by-Design
- Occupancy Sensors
- Showerhead Exchange
- Individual Metering

The Lighting program offers commercial customers incentives up to $300/kW saved for a number of energy efficient lighting technologies, including 34 watt fluorescent lamps, compact fluorescent lamps, high intensity discharge lamps and reflectors. Additional technologies such as energy efficient ballasts are expected to be offered through the program next year. In addition, a new building lighting program offering incentives for energy efficient lighting in new commercial construction is also planned.

The Savings-by-Design program offers commercial customers incentives up to $300/kW saved for customized demand reductions due to efficient building designs, equipment and/or construction for new buildings as well as retrofits of existing buildings. To qualify for the program, proposed demand reducing measures must be sustainable based on building construction, equipment or system design alternatives that improve electrical efficiency.

The Occupancy Sensors program offers incentives of approximately $300/kW saved to customers in the hospitality segment for demand reductions due to the installation of occupancy sensors to control insuite electric heating and cooling.

The Showerhead Exchange program offers incentives of about $250/kW saved (about $10/showerhead) to customers in the multi-residential and hospitality segments for the installation of energy efficient (flow restricting) showerheads.

The Individual Metering program is expected to be approved in late 1989. Incentives of approximately $200/kW saved will likely be offered to developers in the multi-residential segment for installing individual metering in electrically-heated apartment buildings and condominiums.

The Streetlighting Pilot program was launched as a test program during 1989 in cooperation with the Ontario Ministry of Energy. It encourages conversion to energy efficient streetlighting by offering incentives to municipalities worth approximately $330/kW saved.

The Power Saver Plan is a computerized audit-based program (XENCAP) that is also offered to commercial sector customers. This information program is used as an identifier program, and directs customers to appropriate Ontario Hydro incentive programs based on the results of the audit. No megawatt targets are set for this program, although it does contribute to the success of the incentive programs.

The efficient technologies considered in the long-term analysis consist of lighting and motor-related measures. Major lighting technologies include energy efficient ballasts, compact fluorescent lamps, automatic lighting control systems, and T8 (32 watt) fluorescent lamp systems. High-efficiency luminaires were also considered for new commercial buildings exclusively. The motor related measures concentrated primarily on building ventilation systems (energy efficient motors, building automation systems), and air and water balancing of the fan and pump systems, respectively. Other energy efficient technologies (energy efficient appliances, infiltration measures, high performance windows, domestic hot water heating measures) were considered for all-electric apartment buildings. Other than high-efficiency luminaires (new buildings only), all of the technologies considered for the commercial sector are applicable in both existing and new buildings. While current programs may not address all of the technologies listed above, it is assumed that they will be incorporated into programs in the long term.

It should be noted that electronic ballasts were not included in the estimates of potential. There are reliability concerns surrounding this measure, which have resulted in its exclusion from the list of applicable technologies at this time.

Industrial Sector

The current menu of industrial sector programs includes:

- Energy-Efficient Lighting
- High-Efficiency Motors
- Accelerated Paybacks
- Power Saver Services

Incentives up to $300/KW saved for high-efficiency lighting in the industrial sector have been offered through the commercial sector lighting program since March 1989. A lighting efficiency improvement program which is tailored to the industrial sector is expected to be launched in late 1989.

The High-Efficiency Motor program offers customers a rebate of $12/hp (minimum $50) for the installation of a high-efficiency rather than a standard motor. An incentive of $3/hp (minimum $10) will be offered to motor distributors who sell high-efficiency motors.

The Accelerated Payback program promotes process-specific efficiency improvements which are not covered by technology-specific programs. The level of incentive is the lesser of the amount required to reduce the payback to one-and-a-half years or $0.10/KWh for the first year energy savings achieved by the project.

The Power Saver Services program offers funding to identify opportunities for electrical efficiency improvement for process and non-process applications. Two levels of audits are included in this program. Computerized audits (XENCAP) are

being offered to a large number of small and medium-sized plants. The computer software provides estimates of electricity consumption by end use and generic efficiency improvement measures. These audits are offered at no cost to the customer and help to prescreen customers for Consultant Audits.

The second level of audits available are Consultant Audits performed by consulting engineering firms for customers with loads greater than 1 MW. They address only opportunities which will reduce peak demand. Ontario Hydro will cover 100% of the audit cost up to a maximum of $20,000. The maximum funding will increase to $50,000 after an initial 'roll-out' period.

Other information programs will increase awareness of efficiency improvement potential for such technologies as high-efficiency motors, motor sizing, variable speed drives, motor-driven equipment and compressed air systems.

The majority of the efficient technologies considered in the long-term analysis are related to motors or motor-driven systems in industrial plants. Energy efficient motors and variable speed drives are the major technologies reviewed in this sector. Other technologies include high-efficiency lighting, energy recovery measures (eg, heat pumps), energy management measures and a number of industry-specific energy efficient technologies. Industrial sector efficiency improvements are applicable as retrofits and add-ons in existing plants, and are also considered for new plants.

5.2.1.2 The Forecast of Net Load Impact by Sector

The net load impact due to efficiency improvement programs forecasted for the short term (1989-1994) is based on an assessment of the estimates contained in the 1989 Energy Management Branch Business Plan, the quarterly load impact program monitoring reports, and on discussions with various program specialists within the Energy Management Branch. The savings included here are assumed to be net program impacts, that is, excluding free riders and natural conservation. In order to reflect an up-to-date assessment of the expected load impacts, adjustments were made to the earlier estimates contained in the Business Plan.

The forecast of the net load impact of efficiency improvement programs for the long term (1995-2015) is based mainly on the recent in-depth sectoral studies of efficiency improvement potential undertaken by the Energy Economics Section of the Economics and Forecasts Division as input to the 1989 Demand/Supply Plan analysis. The long-term analysis takes into account the findings of various research projects commissioned by the Energy Management Branch, as well as the penetration rate estimates provided by program specialists within the Energy Management Branch.

In these sectoral studies, the maximum and attainable strategic potentials for efficiency improvement in Ontario were derived. The maximum strategic potential refers to the total potential electricity savings available in the market place (equivalent to complete replacement of eligible equipment) that are economic from a societal perspective, yet require Ontario Hydro intervention to be attractive to customers. This intervention is required to overcome barriers to penetration of energy efficient technologies that exist in the market place. Intervention may be in the form of financial incentives, services (e.g. audits) or efficiency levels. Any savings that may occur in the absence of Ontario Hydro intervention (natural conservation) are not included in the estimates of strategic potential. Natural conservation potential is implicit in the Basic Load Forecast. Technologies contributing to the maximum strategic potential have a premium life cycle unit energy cost (including program adminstration costs) less than that of Ontario Hydro's avoided costs. They usually face one or more significant barriers to penetration and/or typically have a payback period to the customer

of more than three years.

In each sector, energy efficient technologies were matched to end-uses, and estimates of costs and savings were derived based on typical applications. The system avoided cost for each technology and application was calculated by System Planning Division and uneconomical options were screened out from the calculation of maximum strategic potential. The maximum strategic potential was then estimated for existing and new stock. Many other variables were also considered in the estimation of technology savings, including expected life, forecast of load growth, building and equipment stocks, eligible markets, etc.

Under the median load growth assumption, the maximum strategic potential in Ontario is estimated to be approximately 4,500 MW for the 1990-2000 period. The commercial sector (2,200 MW) and residential sector (1,740 MW) contribute most to the maximum strategic potential, while the industrial sector (530 MW) is expected to offer less potential savings. By the year 2008, the maximum strategic potential is estimated to be about 6,000 MW under the median load growth assumption. The savings from the commercial, residential and industrial sectors are estimated to be about 2,600 MW, 2,800 MW, and 640 MW respectively.

In order to estimate the proportion of the maximum strategic potential that is thought to be attainable through efficiency improvement programs, estimates of penetration were developed by the Energy Management Branch. The penetration rates were estimated using recent Ontario Hydro research studies, program experience of United States and European utilities, and the actual program experience to date of Ontario Hydro in the Ontario market place.
The penetration rates provided by the Energy Management Branch vary between the sectors. Commercial sector penetration rates are mostly in the 40% to 55% range. Higher penetration rates in specific segments reflect the fact that some building owners are more capable of overcoming potential barriers and can be approached more effectively through Ontario Hydro efficiency improvement programs. In the industrial sector, penetration rates are in the 30% to 50% range for all technologies. The estimates for the residential sector are less uniform, ranging from 3% for some thermal envelope technologies to 50% for water heater programs.

The effectiveness of incentives will be determined by the nature of the market and economic barriers facing each type of efficient technology. In general, it has been assumed that higher levels of incentive will result in greater penetration of the market. Also, it has been assumed that it will be necessary to pay higher levels of incentive in the early 1990s than currently offered in order to meet the demand management targets set by the Corporation.

In each sector, programs are tailored to meet customer needs. They will be delivered through Ontario Hydro offices and participating municipal utilities to customers throughout Ontario with the extensive involvement of manufacturers, distributors, contractors, consulting engineers, architects, energy management consultants and industry associations.

The attainable strategic potential was estimated using the estimates of the maximum economic potential and the penetration rate. As mentioned above, the amount of attainable savings will depend on factors such as program design, the type and level of incentives and services as well as practical considerations.

Residential Sector

In preparing the forecast of the net load impact of electrical efficiency improvements, adjustments were made to the Energy Management Business Plan (1990-1994) estimates in several program areas, including those for ground source heat pumps, mandation of an EE housing standard, heat recovery ventilation, and in

the Agricultural Segment. In total, the incentive-driven programs offered in the residential sector are expected to reduce the peak load by 130 MW over the 1990-1994 period. This forecast is about 63 MW higher than the 1988 forecast, reflecting a much more aggressive programming approach this year which includes higher incentives to customers.

The longer term prospects for the residential sector assume more programs and higher incentives to be offered in order to achieve more electrical efficiency improvement savings. The savings are expected to increase gradually in the initial few years when the programs are being designed and launched. By 1995, the programs are expected to be in high gear, reaping the results of earlier programming efforts.

The cumulative total savings associated with efficiency improvement measures in the residential sector are expected to reach 580 MW by the year 2000. The sector could contribute up to 925 MW of savings by 2010 and 1,000 MW by the year 2015. After 2010, the potential for additional savings is expected to come mainly from the new housing segment because most of the retrofit potential in the existing housing segment will have been captured.

Commercial Sector

The commercial sector forecast reflects the Energy Management Branch estimates for incentive-driven efficiency improvement programs in the short term (1989-1994). The 1989 estimate of load reduction has been adjusted for the fact that the programs came on line during 1989 rather than at the start of the year. Further adjustments have been made to account for the lead time necessary between program launch dates and connected megawatt reductions on the system. These adjustments were made to the load reduction impact associated with the Savings-by-Design Program, where the estimated lead time between project approval and connected load reduction is between six and eighteen months.

It should be noted that the Lighting Program estimates for load reduction exclude savings attributable to 34 watt fluorescent lamps. This technology is assumed to contribute to the natural conservation potential over the next decade and is implicitly accounted for in the Basic Load Forecast.

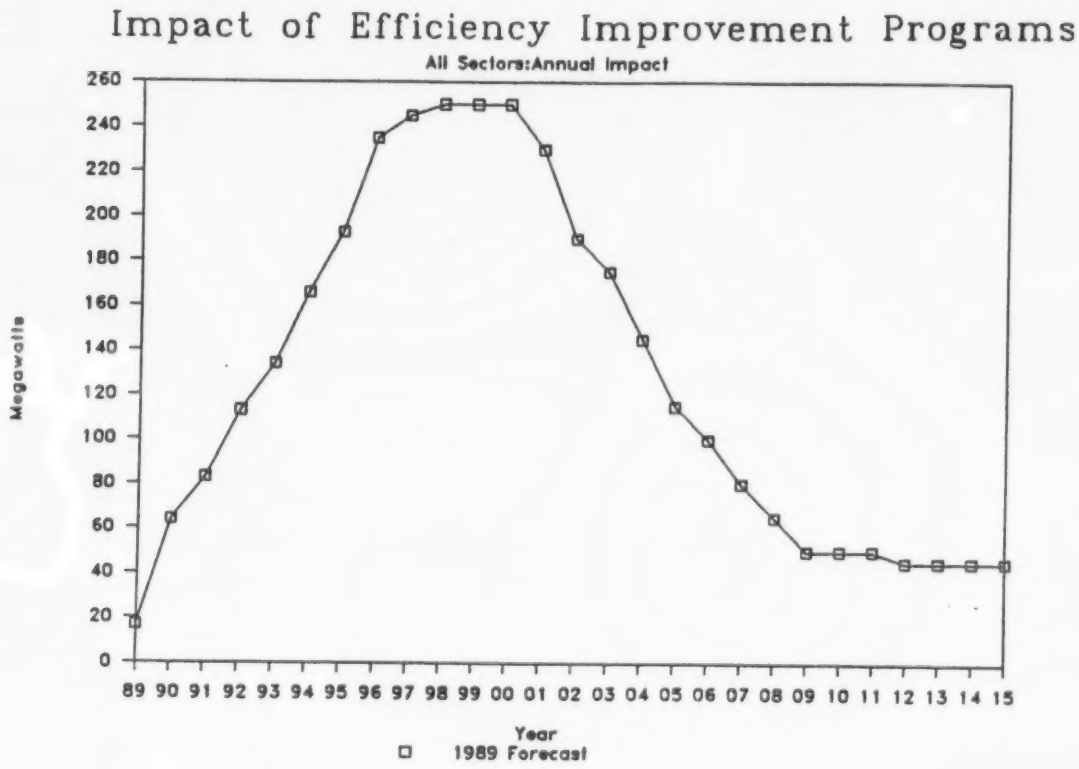
For the long term, the net load impact in the commercial sector due to efficiency improvement programs is estimated to be 1,000 MW by the year 2000. For 1995 to 2000, the megawatt reductions ramp up quickly to levels consistent with full program implementation and the assumption that a broad menu of programs offering higher financial incentives than current levels is available. For the years after 2000, the annual net load impacts due to efficiency improvement programs decline, as the existing stock available for retrofit declines (although new stock opportunities continue). By 2010, the commercial sector net load impact due to efficiency improvement programs is estimated at just over 1,600 MW and reaches over 1,700 MW by 2015.

Industrial Sector

The forecast of the net load impact of electrical efficiency improvements in the industrial sector closely reflects the Energy Management Business Plan estimates. The adjustments made to the Business Plan estimates are very minor. The forecast for 1994 exceeds the Business Plan estimates for incentive-driven programs by 5 MW. The adjustment was primarily made for smoothing purposes. The current forecast exceeds last year's forecast by 20 MW over the 1989-1993 period. This is due to an increase of 5 MW each year between 1990 and 1993 because of a very positive response to date to the Accelerated Paybacks program.

In the industrial sector, the annual impact is expected to reach its highest level over the period 1996 to 2000, when a full menu of programs with significantly higher financial incentives will be offered. The cumulative impact to the year 2000 is expected to be 420 MW, unchanged from last year's forecast. Beyond the year 2000, the annual program impact gradually tapers off. This reflects the fact that most of the potential from existing equipment will have been captured, while potential for new applications continues. The impact over the period 2000 to 2010 is higher than was expected last year. This reflects the view that Demand Management Programs will continue beyond the year 2000. By the year 2010, a cumulative impact of 615 MW is expected. The cumulative impact to the year 2015 is expected to be 700 MW.

Figure 5.2.1.2



5.2.2 Load-Shifting Programs

5.2.2.1 Program Description

Time-of-use rates and incentives for thermal cool storage are the major load-shifting programs currently being offered by Ontario Hydro. Direct control of residential and apartment water heaters is another load-shifting program which may be used in the future if the response to time-of-use rates is insufficient to achieve Ontario Hydro's load-shifting targets. Other programs may be developed to offer customers additional incentives to shift load from the peak to the off-peak period.

The time-of-use rate pricing and costing system came into effect January 1, 1989 for all Ontario Hydro direct customers, all large customers of municipal utilities and those municipal utilities which opted for time-of-use billing.

The new rate structure is being phased in over four years. The revenue collected from demand and energy charges will be gradually altered from the previous 50/50 split to 42/58 by 1992. The capacity/energy split will remain at 42/58 for a period of ten years.

The rate structure includes four time-of-use periods: winter peak, winter off-peak, summer peak and summer off-peak. Summer is defined as April through September and winter as the remaining months. The peak period in each season is from 7 am to 11 pm Monday to Friday except for public holidays. All other hours are off-peak.

At full implementation, demand charges will be 40% higher during the winter than during the summer and will be applied only to peak period demand. Unit energy costs during the peak period will be 25% higher than during the off-peak in the winter and 60% higher than the off-peak in the summer. Average winter unit energy costs will be 25% higher than average summer unit energy costs.

It is mandatory for all Ontario Hydro direct customers and the large customers of the Municipal Utilities to be billed under time-of-use rates. The municipal utilities may choose whether to be billed under the time-of-use rate or the traditional rate structure. By January 1, 1990, a total of 158 municipal utilities and the two distributing companies will be billed under time-of-use rates. Together these customers represent 95% of the municipal load. Several municipal utilities have indicated that they plan to offer a time-of-use rate structure to their remaining general service and/or residential customers in the future.

The thermal cool storage program is being offered to commercial sector customers and is designed to shift a portion of their air conditioning load to the off-peak period. Over the 1989 to 1994 period, the cumulative target for this program is 65 MW. The current view is that this program will result in a reduction in peak demand during the summer period. While there may be some impact on the winter peak load, the evidence is not yet conclusive and the magnitude of any impact is not known. For this reason, the impact of load-shifting associated with thermal cool storage is not included in determining the Primary Load Forecast.

5.2.2.2 Forecast of Impact of Load-Shifting Programs

The estimates of the impact of load shifting programs for the short-term period to 1994 are based on information incorporated in the Energy Management Branch business plan as well as the results of a questionnaire on the impact of time-of-use rates distributed to customers in early 1989. Information provided through the Industrial Sector monitoring activity and an analysis of direct customer billing records has also been considered.

The load-shifting targets for the period 1989 to 1994 contained in the Energy Management Branch business plan indicate a cumulative reduction in winter peak demand of 575 MW. This excludes the impact of thermal cool-storage programs (targeted at 65 MW) which are not expected to reduce peak load during the winter. The remaining targets are almost exclusively the expected impact of time-of-use rates. A target of 2 MW is included for direct control of apartment water heaters, which reflects the expected impact of an Ontario Hydro test program.

The respondents to the time-of-use rate questionnaire indicated they would cut their winter peak by 45 MW in 1989 due to the new rate structure. Given the response rate to the questionnaire, this tends to support the target of a 77 MW winter peak reduction in 1989. The information being gathered by the Energy Management Branch through an analysis of direct customer billing data and through

the industrial program monitoring activity are generally consistent with the questionnaire results. It should be noted that the 1989 target may be optimistic given the uncertainty regarding the response to time-of-use rates for the customers who did not complete the questionnaire.

The questionnaire results indicate little incremental load impact due to time-of-use rates beyond 1989. This may be because customers cannot accurately estimate their response to time-of-use rates beyond the very short term. Several municipal utilities indicated they have plans to offer time-of-use rates to their remaining general service class and/or residential customers in the future, but did not provide an estimate of the impact on their load. The results of future questionnaires will help to determine whether the small incremental impact is realistic. Because of this uncertainty, the questionnaire results for the 1990 to 1994 period are not considered reliable and are not reflected in the forecast.

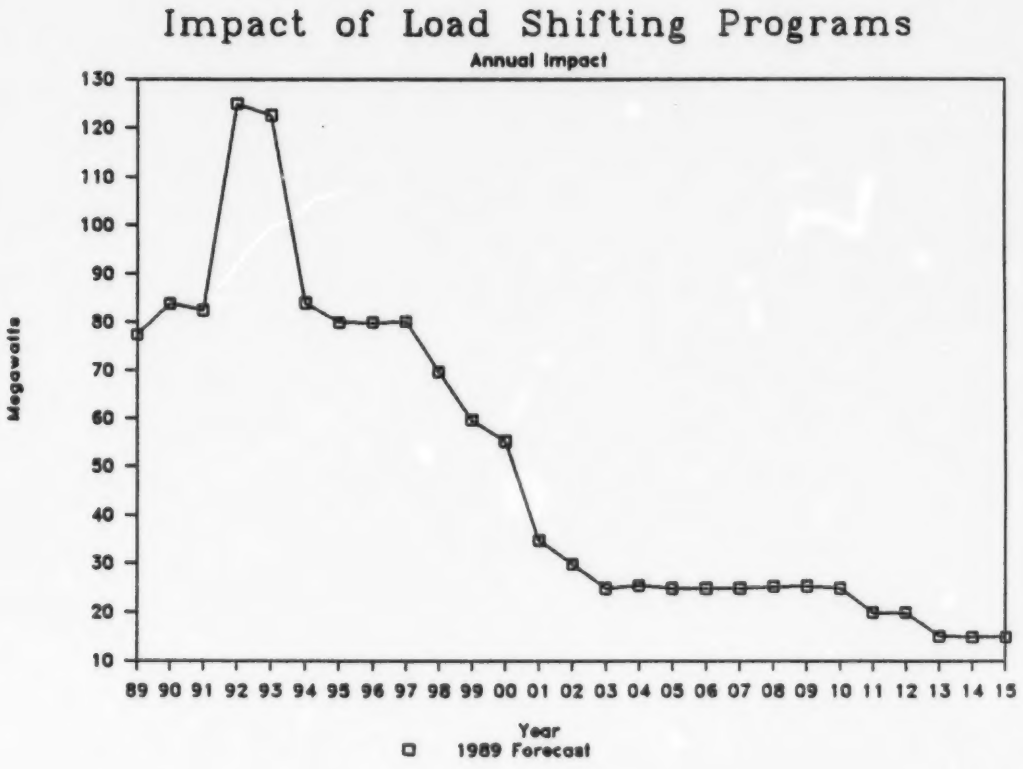
The cumulative impact in this year's forecast is 89 MW less than expected last year (491 MW vs. 580 MW) over the period 1989 to 1993. Several factors contributed to this difference. Less emphasis is now expected to be placed on direct control of water heaters in residential and commercial buildings. More emphasis is targeted for the thermal cool-storage program in the commercial sector, which as indicated earlier, is not expected to result in a reduction in winter peak demand. Finally, a portion of the load-shifting target in the industrial sector (30 MW) has been delayed beyond the period of the current business plan.

The long-term impact of load-shifting programs on system peak demand is based on the results of several Ontario Hydro studies which investigate time-of-use rates and the implementation experience of other utilities.

The cumulative impact is unchanged from last year at 1000 MW in the year 2000. This reflects the system's maximum load shifting potential in the year 2000 as estimated by System Planning Division. The reduction in the short-term impact from last year's forecast is expected to be captured in the following years. This results in a smoother pattern of expected load shifting to the year 2000.

Growth in the total system load is expected to result in the opportunity for additional load shifting beyond the year 2000. The forecast for this period is unchanged from last year with a cumulative reduction in winter peak demand of 1265 MW by 2010. By 2015 the cumulative impact is estimated to be 1350 MW (see Table 5.5.1).

Figure 5.2.2.2



5.2.3 Forecast of the Net Load Impact of Demand Management Programs

In generating this forecast, it is assumed that the Corporation will pursue an intensive demand management strategy over the next two decades. In particular, a critical assumption is that a comprehensive set of demand management programs backed by significant financial incentives will be in place during the early 1990s.

In deriving the estimates to the year 2000 and beyond, the following assumptions were made:

- intensive demand management research will be carried out and completed over the next three to four years;

- programs planned and underway for the 1990-94 period will generate much-needed information, data and internal expertise;

- expenditures in excess of $2 billion (in 1989 dollars) will be made for financial incentives by the year 2000, involving incentives up to the avoided cost of incremental supplies for the Ontario Hydro power system;

- time-of-use rates will be widely offered to the customers served by Ontario Hydro and the Municipal utilities. Where time-of-use rates are not available directly to the customers, load shifting technologies will be promoted to achieve an equivalent impact;

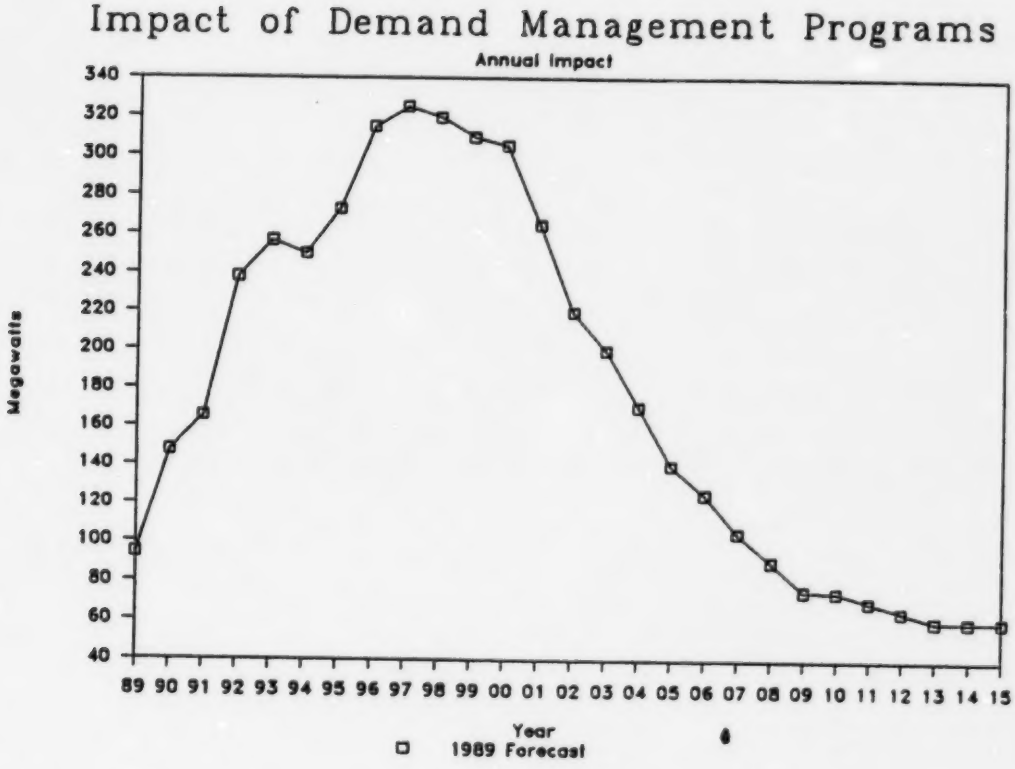
- the industrial infrastructure (contractors, builders, architects, etc) and institutional environment (eg, municipal electric utilities) will be in place to permit gearing up of full-scale programs;

- any other major financial, informational and institutional barriers will be overcome during program design and implementation; and

- given the above considerations, Ontario Hydro will be in a position to launch a full spectrum of effective demand management programs by the early 1990s.

Table 5.2.3.1 presents the estimated net peak load impact associated with the incentive-driven demand management programs. The year 2000 target of 3,000 MW set by the corporation has been embedded in the forecast. The cumulative impact of electrical efficiency improvement programs by the year 2000 is distributed by sector as follows: 50 per cent for the commercial sector; 29 per cent for the residential sector; and 21 per cent for the industrial sector.

Figure 5.2.3



In order to translate the peak megawatt savings associated with efficiency improvement programs into an annual terawatt hour per year reduction, the following estimated load factors are used: 30% for the residential sector to 1994 rising to 50% by the year 2000; 65 per cent for the commercial sector; and 75 per cent for the industrial sector. Table 5.2.3.2 shows the annual terawatt hour reduction based on the above load factors.

In the case of time-of-use rates, it is assumed that the impact is purely one of load shifting and that there will be no increase or reduction in annual TW.h. Research will be required to determine whether customer response in peak periods is exactly offset in off-peak periods. It will take several years at least to assess this for Ontario Hydro's time-of-use rate structure.

Table 5.2.3.1 Net Load Impact of Demand Management Programs

Year	Efficiency Improvement Programs MW	Efficiency Improvement Programs Cumulative MW	Load Shifting Programs MW	Load Shifting Programs Cumulative MW	Total Impact MW	Total Impact Cumulative MW
1989	17	17	77	77	94	94
1990	64	81	84	161	148	242
1991	83	164	82	244	166	408
1992	113	277	125	369	238	646
1993	134	411	123	491	257	902
1994	166	577	84	575	250	1152
1995	193	770	80	655	273	1425
1996	235	1005	80	735	315	1740
1997	245	1250	80	815	325	2065
1998	250	1500	70	885	320	2385
1999	250	1750	60	945	310	2695
2000	250	2000	55	1000	305	3000
2001	230	2230	35	1035	265	3265
2002	190	2420	30	1065	220	3485
2003	175	2595	25	1090	200	3685
2004	145	2740	25	1115	170	3855
2005	115	2855	25	1140	140	3995
2006	100	2955	25	1165	125	4120
2007	80	3035	25	1190	105	4225
2008	65	3100	25	1215	90	4315
2009	50	3150	25	1240	75	4390
2010	50	3200	25	1265	75	4465
2011	50	3250	20	1285	70	4535
2012	45	3295	20	1305	65	4600
2013	45	3340	15	1320	60	4660
2014	45	3385	15	1335	60	4720
2015	45	3430	15	1350	60	4780

Source: Energy Economics Section
Economics & Forecasts Division

Table 5.2.3.2 Annual TW.h Reduction

Efficiency Improvement Programs

Year	Per Year	Cumulative
1989	0.055	0.055
1990	0.241	0.296
1991	0.399	0.695
1992	0.517	1.212
1993	0.627	1.839
1994	0.746	2.585
1995	0.864	3.449
1996	1.111	4.560
1997	1.267	5.827
1998	1.323	7.150
1999	1.362	8.513
2000	1.362	9.875
2001	1.307	11.182
2002	1.148	12.330
2003	0.998	13.327
2004	0.874	14.201
2005	0.716	14.917
2006	0.592	15.510
2007	0.492	16.001
2008	0.396	16.398
2009	0.318	16.715
2010	0.278	16.993
2011	0.278	17.272
2012	0.262	17.533
2013	0.245	17.779
2014	0.245	18.024
2015	0.245	18.269

5.3 Load Displacement Non-Utility Generation Forecast

Non-utility generation (or NUG) is electrical generation owned and operated in Ontario by producers other than Ontario Hydro. Non-utility generators include private and municipal utilities, and private power producers. The electricity they generate may be either purchased outright by Hydro for distribution to its customers, or else used to meet the producer's own electricity needs.

Non-utility generation which is sold to Hydro is known as "purchase" generation. The NUG generators involved are interconnected with the province-wide transmission and distribution network. Like purchases from other utilities, purchased generation is considered to be a supply option and is not investigated further here.

On the other hand, non-utility generation which supplies electricity to meet the producer's own needs or is directly purchased by a customer other than Hydro is referred to as "load displacement" generation. It is so termed because such generation displaces load which Hydro would otherwise have been responsible for supplying.
Hydro has created a Non-Utility Generation Division responsible for promoting economic non-utility generation in Ontario. Although this type of generation is far from new to Ontario, Hydro's policy is to give it much greater emphasis

now than in the past, especially where such generation is produced from renewable or waste resources or at high efficiency. As part of its promotional activities, Hydro conducts an annual workshop with non-utility generators, provides financial assistance to qualifying developers and participates in several committees in order to encourage the NUG industry.

For non-utility generators with capacities up to five MW, Hydro offers to purchase electricity at both flat and time-differentiated rates under standard contract conditions. Special contract conditions may be negotiated at the request of the generator to help meet the specific needs of individual projects.

For projects over 5 MW, Hydro's policy is to implement a solicitation process for non-utility generation capacity. Under this arrangement, Hydro will issue periodic requests for proposals (RFPs) to solicit projects. The underlying philosophy is to ensure non-utility generators of fair and consistent treatment.

The Non-Utility Generation Division has forecasted that over 1600 MW of new non-utility generation capacity is expected to be in operation by the end of the year 2000. By 2015, over 2600 MW of new generation capacity is expected. This forecast was based on the attainable potential for small hydro cogeneration, and other thermal generation in Ontario assuming 1989 purchase rates, expected gas contract prices, equipment costs, and a minimum internal after tax rate of return of 15%. The forecast also accounts for the retirement of NUG facilities. NUG retirements are subtracted from new additions to yield the net additions. Energy from these additions was based on a capacity factor of 65% for hydraulic facilities and 80% for cogeneration and other thermal facilities.

Based on currently identified NUG projects, about 44% of the new generation capacity is expected to be used for load displacement in the period to 2000. The remainder is expected to be purchase generation. In the long term (beyond the year 2000), this proportion is about 40%. The reduction is due in part to the fact that future generation will also be obtained from third party transactions like the Boise Cascade/ICG project in Fort Frances which is treated as purchase generation.

There currently exists over 1200 MW of load displacement generation that has been developed in response to normal market forces. Without Hydro's programs, load displacement NUGs would have been expected to experience a 'natural' growth in future. To account for this component, a portion of the load displacement forecast is classified as natural. The remainder of the load displacement forecast is referred to as incentive or program-driven load displacement. It is the net load displacement generation that is induced by Ontario Hydro's NUG programs and is similar to the net load impact of program-driven demand management.

The natural load displacement forecast was based on a linear projection of past growth minus forecasted retirements. By the end of the year 2000, it is forecasted that a total of 254 MW of net NUG additions would have occurred anyway. The natural component of load displacement NUGs is subtracted out as part of the adjustment from Total Ontario Electricity Demand to the Basic Load Forecast.

The difference between the total load displacement forecast and the natural load displacement forecast is referred to as the program-driven component. By the end of the year 2000, it is forecasted that 402 MW of new program-driven NUG additions are expected. The program-driven load displacement generation is subtracted from the Basic Load Forecast.

Before the natural and program-driven components of load displacement non-utility generation can be implemented in the load forecast process, two other factors must be accounted for, namely, dependable capacity and demand displacement. Factoring in dependable capacity reduces the total forecast of NUG capacity available to account for such contingencies as outages and low river flows. The dependable capacity for all non-utility generation is considered to be 90% of installed capacity.

Factoring in demand displacement increases NUG load displacement capacity. Similarly to demand management options, load displacement NUGs generally reduce Ontario Hydro's transmission line losses. To credit load displacement generators for this benefit, a demand displacement factor of 105% is assumed.

The forecast for each component of load displacement non-utility generation accounting for dependability and demand displacement is shown below.

Table 5.4.1 1989 Load Displacement Non-Utility Generation Forecast

Year	Natural Dependable		Program-Driven Dependable		Total	
	Capacity (MW)	Energy (TW.h)	Capacity (MW)	Energy (TW.h)	Capacity (MW)	Energy (TW.h)
1993	80	611	309	2292	389	2902
2000	228	1704	401	2978	629	4682
2010	398	2965	439	3259	837	6224
2015	483	3596	458	3399	941	6995

Compared to the 1988 NUG forecast, the 1989 NUG Forecast in total represents an increase from 1000 MW to 1600 MW in expected new NUG additions. However, this increase is not reflected in every component of the forecast. In the short term, the natural and program-driven load displacement values are higher than the 1988 forecast. However, in the long term, even though the natural forecast is somewhat higher in the 1989 forecast, the program-driven component is significantly less than the 1988 forecast. This does not represent a decrease in expectation in NUG development. Rather it is recognition that more NUG development will occur naturally and that many new potential sites will be purchase NUGs rather than load displacement. Furthermore, dependable capacity rather than installed capacity has been provided for input into the 1989 forecast.

The forecast details are summarized in Tables 5.4.2, 5.4.3 and 5.4.4.

Table 5.4.2: Load Displacement Non-Utility Generation - Natural Load Displacement Forecast

Year	Net Additions MW	Cumulative Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1989	(1)	(1)	(1)	(8)
1990	50	49	35	274
1991	3	52	37	288
1992	23	75	59	449
1993	23	98	80	611
1994	23	121	102	772
1995	23	144	124	933
1996	22	166	145	1,087
1997	22	188	165	1,241
1998	22	210	186	1,395
1999	22	232	207	1,550
2000	22	254	228	1,704
2001	18	272	245	1,830
2002	18	290	262	1,956
2003	18	308	279	2,082
2004	18	326	296	2,208
2005	18	344	313	2,335
2006	18	362	330	2,461
2007	18	380	347	2,587
2008	18	398	364	2,713
2009	18	416	381	2,839
2010	18	434	398	2,965
2011	18	452	415	3,091
2012	18	470	432	3,218
2013	18	488	449	3,344
2014	18	506	466	3,470
2015	18	524	483	3,596

Notes: 1. Negative indicates natural retirement exceeds natural additions.

2. Dependable capacity calculated as follows:

   i 70% of rated capacity for hydraulic facilities
   ii 90% of rated capacity for thermal facilities
   iii All faciliites increased by 105% due to line loss savings credit.

3. Energy based on 80% load factor for thermal and 65% for hydraulic.

4. 1989 values based on expected in-service dates.

Table 5.4.3: Load Displacement Non-Utility Generation - Program Driven Load Displacement Forecast

Year	Net Additions MW	Cumulative Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1989	61	61	58	93
1990	46	107	101	750
1991	78	185	175	1,296
1992	71	256	242	1,794
1993	71	327	309	2,292
1994	25	352	333	2,467
1995	26	378	357	2,649
1996	15	393	371	2,754
1997	12	405	383	2,838
1998	7	412	389	2,887
1999	1	413	390	2,894
2000	12	425	402	2,978
2001	4	429	405	3,006
2002	4	433	409	3,034
2003	4	437	413	3,062
2004	4	441	417	3,091
2005	4	445	421	3,119
2006	4	449	424	3,147
2007	4	453	428	3,175
2008	4	457	432	3,203
2009	4	461	436	3,231
2010	4	465	439	3,259
2011	4	469	443	3,287
2012	4	473	447	3,315
2013	4	477	451	3,343
2014	4	481	455	3,371
2015	4	485	458	3,399

Notes:
1. Dependable capacity calculated as in Table 5.4.2
2. Energy based on 80% load factor for thermal and 65% for hydraulic
3. 1989 values based on expected in-service dates
4. Program Driven is the difference between natural and total load displacement

Table 5.4.4: Load Displacement Non-Utility Generation - Total Load Displacement Forecast

Year	Net Additions MW	Cumulative Additions MW	Cumulative Dependable MW	Yearly Energy GW.h
1989	60	60	56	85
1990	96	156	136	1,024
1991	81	237	212	1,585
1992	94	331	301	2,243
1993	94	425	389	2,902
1994	48	473	435	3,239
1995	49	522	481	3,582
1996	37	559	516	3,841
1997	34	593	548	4,080
1998	29	622	576	4,283
1999	23	645	597	4,444
2000	34	679	629	4,682
2001	22	701	650	4,836
2002	22	723	671	4,991
2003	22	745	692	5,145
2004	22	767	713	5,299
2005	22	789	733	5,453
2006	22	811	754	5,607
2007	22	833	775	5,761
2008	22	855	796	5,916
2009	22	877	817	6,070
2010	22	899	837	6,224
2011	22	921	858	6,378
2012	22	943	879	6,532
2013	22	965	900	6,687
2014	22	987	921	6,841
2015	22	1,009	941	6,995

Notes: 1. Dependable capacity calculated as in Table 5.4.2

2. Energy based on 80% load factor for thermal and 65% for hydraulic

3. 1989 values based on expected in-service dates

4. At-Will energy not included

TABLE A

COMPARISON OF TOTAL SYSTEM DEMANDS WITH EARLIER FORECASTS

ONTARIO PRIMARY DEMAND

20-MINUTE WINTER PEAK DEMAND - Megawatts

		FORECAST MADE IN						
Winter	Actual	1983	1984	1985	1986	1987	1988	1989
1982/83	17578							
1983/84	18896	18227						
1984/85	19390	18819	19438					
1985/86	20668	19404	19915	19846				
1986/87	20609	20035	20531	20386	21222			
1987/88	22593	20603	21100	20917	21817	22018		
1988/89	23068	21121	21721	21510	22520	22676	23154	
1989/90	24399*	21636	22198	22116	23065	23245	23688	24324
1990/91		22018	22895	22683	23558	23898	24166	24868
1991/92		22409	23523	23312	23995	24359	24871	25600
1992/93		22851	24116	24029	24364	24892	25468	26152
1993/94		23352	24689	24775	24788	25441	25916	26636
1994/95		23927	25233	25545	25279	25936	26324	27136
1995/96		24545	25859	26029	25766	26291	26423	27604
1996/97		25161	26524	26660	26264	26785	26683	28138
1997/98		25796	27171	27277	26734	27288	26984	28501
1998/99		26418	27824	27949	27135	27829	27422	28919

ANNUAL ENERGY DEMAND - Terawatt Hours

		FORECAST MADE IN						
Year	Actual	1983	1984	1985	1986	1987	1988	1989
1982	100.8							
1983	106.1	103.3						
1984	112.3	109.0	111.3					
1985	116.0	112.6	114.5	115.1				
1986	120.6	116.3	117.2	117.7	121.0			
1987	126.5	119.9	120.7	121.1	125.0	125.2		
1988	134.4	123.5	124.0	124.4	129.0	129.7	133.1	
1989	140.8	126.2	127.0	127.4	132.1	133.2	136.9	139.2
1990		129.3	129.8	130.9	135.0	137.0	140.2	142.7
1991		131.6	133.9	134.2	137.9	140.5	143.6	146.5
1992		134.3	137.5	138.0	142.3	144.3	148.3	151.5
1993		136.6	141.0	142.2	145.5	147.9	152.3	154.7
1994		139.6	144.4	146.6	148.8	151.9	155.4	158.3
1995		143.0	147.5	151.2	152.3	155.5	158.2	161.5
1996		146.7	151.2	154.1	155.7	158.0	159.2	166.2
1997		150.4	155.1	157.8	159.0	161.3	161.7	169.0
1998		157.9	158.9	161.4	162.0	168.1	167.1	171.8

* The figure given for 20-minute annual peak for 1989 represents the peak demand imposed on Ontario Hydro and includes 627 MW of unserved demand on Interruptible contracts and 348 MW unserved due to voltage reductions.

TABLE A1

COMPARISON OF 20-MINUTE WINTER PEAK DEMANDS WITH EARLIER FORECASTS

EAST SYSTEM - ONTARIO PRIMARY DEMAND
Megawatts

		FORECAST MADE IN						
Winter	Actual	1983	1984	1985	1986	1987	1988	1989
1982/83	16793							
1983/84	18009	17404						
1984/85	18525	17975	18553					
1985/86	19711	18537	18989	18905				
1986/87	19679	19112	19572	19445	20261			
1987/88	21615	19661	20127	19953	20834	21020		
1988/89	22081	20155	20738	20506	21518	21675	22123	
1989/90	1133*	20646	21194	21096	22027	22215	22664	23274
1990/91		21011	21860	21637	22488	22867	23140	23808
1991/92		21384	22459	22237	22930	23324	23811	24527
1992/93		21806	23025	22921	23279	23833	24396	24859
1993/94		22284	23572	23632	23682	24356	24822	25334
1994/95		22833	24091	24367	24150	24829	25245	25760
1995/96		23422	24689	24829	24610	25166	25342	26655
1996/97		24010	25324	25430	25072	25638	25621	27107
1997/98		24616	25942	26019	25520	26120	25919	27446
1998/99		25209	26565	26661	25903	26637	26351	27839

WEST SYSTEM - ONTARIO PRIMARY DEMAND
Megawatts

		FORECAST MADE IN						
Winter	Actual	1983	1984	1985	1986	1987	1988	1989
1982/83	870							
1983/84	932	900						
1984/85	961	922	955					
1985/86	1012	948	998	995				
1986/87	1015	1008	1033	995	977			
1987/88	1035	1030	1048	1019	1020	1044		
1988/89	1043	1056	1060	1062	1049	1049	1076	
1989/90		1082	1083	1078	1075	1084	1070	1103
1990/91		1101	1117	1106	1125	1085	1074	1128
1991/92		1120	1148	1136	1152	1092	1109	1161
1992/93		1142	1177	1171	1153	1111	1123	1170
1993/94		1167	1205	1208	1174	1138	1167	1112
1994/95		1196	1232	1245	1198	1163	1186	1112
1995/96		1227	1262	1269	1226	1187	1174	1141
1996/97		1258	1295	1300	1251	1205	1152	1169
1997/98		1290	1326	1330	1278	1230	1162	1182
1998/99		1321	1358	1362	1302	1255	1166	1209

* Includes 941 MW of unserved demand
** Includes 34 MW of unserved demand

TABLE C

LOAD FORECAST REPORT NO. 891211
ONTARIO PRIMARY DEMANDS - TOTAL SYSTEMS

Year	20 Min Annual Peak MW	Annual Energy MW.h	Annual Energy Avg MW	Load Factor
1946	2,036.1	10,575,379.3	1,207.2	59.3
1947	2,262.2	12,495,821.2	1,426.5	63.1
1948	2,393.0	12,991,064.4	1,478.9	61.8
1949	2,443.7	13,511,035.9	1,542.4	63.1
1950	2,753.1	15,175,583.7	1,732.4	62.9
1951	3,063.1	17,241,303.9	1,968.1	64.3
1952	3,247.7	18,401,371.7	2,094.8	64.5
1953	3,442.8	19,590,139.1	2,236.3	65.0
1954	3,655.7	20,471,343.9	2,336.8	63.9
1955	4,183.2	22,877,271.2	2,611.4	62.4
1956	4,468.5	25,135,134.1	2,861.4	64.0
1957	4,737.6	27,002,762.0	3,082.4	65.1
1958	5,093.1	27,979,394.9	3,193.8	62.7
1959	5,510.6	31,143,172.8	3,555.0	64.5
1960	5,699.8	32,319,968.2	3,679.4	64.6
1961	5,902.9	33,569,282.4	3,831.9	64.9
1962	6,247.0	35,488,962.2	4,051.1	64.9
1963	6,750.6	37,288,964.1	4,256.5	63.1
1964	7,163.9	40,305,468.3	4,588.5	64.1
1965	7,818.4	43,511,759.8	4,967.1	63.5
1966	8,565.6	48,054,384.4	5,485.7	64.0
1967	8,963.8	51,355,505.0	5,862.5	65.4
1968	9,994.4	55,788,374.7	6,351.1	63.5
1969	10,555.4	59,424,443.4	6,783.6	64.3
1970	11,288.7	64,287,605.7	7,338.8	65.0
1971	11,534.5	68,132,582.0	7,777.7	67.4
1972	12,738.8	73,495,941.4	8,367.2	65.7
1973	13,605.4	78,162,478.1	8,922.6	65.6
1974	13,538.1	82,695,005.7	9,440.1	69.7
1975	14,512.5	84,220,853.4	9,614.2	66.2
1976	15,895.3	90,851,705.2	10,343.0	65.1
1977	15,901.1	92,853,681.9	10,599.7	66.7
1978	16,246.7	95,371,714.5	10,887.2	67.0
1979	16,364.7	98,126,082.3	11,201.6	68.4
1980	16,807.8	100,172,734.9	11,404.0	67.8
1981	17,189.0	101,658,168.0	11,604.8	67.5
1982	18,123.6	100,835,597.9	11,510.9	63.5
1983	18,791.5	106,071,164.8	12,108.6	64.4
1984	18,896.0	112,293,482.0	12,783.8	67.6
1985	20,473.0	116,048,994.0	13,247.6	64.7
1986	20,668.0	120,573,918.0	13,764.1	66.6
1987	20,524.0	126,455,099.0	14,435.5	70.3
1988	23,012.0	134,394,697.0	15,299.9	66.5
1989*	24,399.0	140,770,100.0	16,069.6	65.9

* The figure given for 20-minute annual peak for 1989 represents the peak demand imposed on Ontario Hydro and includes 627 MW of unserved demand on Interruptible contracts and 348 MW unserved due to voltage reductions.

ONTARIO PRIMARY DEMANDS

LONG TERM FORECAST TO 2015

Note: For years marked with ** the growth of the Basic Load over the course of the year is less than the increase in the total of EIP, TOU and load displacement NUG impacts. These impacts are deducted from the Basic to prepare the Primary. As a result the January 20 minute peak MW in those years is greater than the following December peak in the same year. For years marked with **** the same holds true for the 1-hour peaks.

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1989													
20 Min Peak MW	23604	22497	21888	19594	18664	19197	19612	19912	18288	19649	21757	23821	20706.9
1 Hour Peak MW	23366	22359	21706	19443	18526	19085	19505	19807	18144	19443	21563	23668	20551.3
Energy GWH	13504	12093	12522	10836	10609	10549	11034	11138	10334	11324	12018	13224	139182.4
Energy Av MW	18150	17995	16831	15049	14259	14651	14830	14970	14353	15221	16691	17774	15888.4
*L.F. %	77.7	80.5	77.5	77.4	77.0	76.8	76.0	75.6	79.1	78.3	77.4	75.1	77.3
1990													
20 Min Peak MW	24324	23129	22440	19969	19007	19606	20074	20274	18568	19954	22210	24325	21156.6
1 Hour Peak MW	24079	22988	22252	19815	18867	19492	19966	20169	18422	19744	22011	24155	20996.7
Energy GWH	13959	12481	12873	11071	10832	10811	11319	11382	10541	11553	12325	13590	142738.1
Energy Av MW	18761	18573	17303	15376	14559	15015	15214	15298	14640	15529	17118	18266	16294.3
*L.F. %	77.9	80.8	77.8	77.6	77.2	77.0	76.2	75.9	79.5	78.6	77.8	75.6	77.6
1991													
20 Min Peak MW	24868	23595	22894	20375	19442	20042	20527	20818	19035	20416	22742	25015	21647.4
1 Hour Peak MW	24615	23450	22699	20217	19297	19924	20416	20709	18885	20197	22535	24854	21483.2
Energy GWH	14294	12767	13173	11341	11127	11096	11621	11720	10839	11851	12645	13992	146466.7
Energy Av MW	19212	18999	17706	15751	14956	15411	15620	15753	15054	15929	17563	18806	16719.9
*L.F. %	78.1	81.0	78.0	77.9	77.5	77.3	76.5	76.1	79.7	78.9	77.9	75.7	77.8
1992													
20 Min Peak MW	25600	24286	23543	20915	19966	20611	21125	21413	19543	20955	23372	25684	22251.0
1 Hour Peak MW	25336	24136	23340	20751	19816	20489	21010	21300	19388	20728	23158	25517	22080.8
Energy GWH	14750	13645	13572	11674	11454	11444	11999	12092	11168	12208	13038	14464	151510.0
Energy Av MW	19826	19605	18243	16213	15395	15895	16128	16253	15511	16408	18109	19441	17248.4
*L.F. %	78.3	81.2	78.2	78.1	77.7	77.6	76.8	76.3	80.0	79.2	78.2	76.2	78.1
1993													
20 Min Peak MW	26152	24781	24019	21290	20331	20989	21530	21821	19877	21318	23830	26202	22678.3
1 Hour Peak MW	25880	24627	23810	21122	20177	20864	21412	21706	19719	21083	23611	26031	22503.3
Energy GWH	15136	13517	13914	11951	11726	11716	12295	12384	11423	12485	13356	14845	154748.0
Energy Av MW	20344	20114	18702	16598	15761	16273	16525	16645	15865	16781	18550	19953	17665.3
*L.F. %	78.6	81.7	78.6	78.6	78.1	78.0	77.2	76.7	80.4	79.6	78.6	76.7	78.5
1994													
20 Min Peak MW	26636	25221	24435	21616	20671	21354	21925	22222	20217	21671	24270	26723	23080.1
1 Hour Peak MW	26356	25065	24220	21445	20515	21229	21806	22107	20057	21430	24046	26550	22902.2
Energy GWH	15492	13833	14228	12204	11984	11980	12580	12667	11681	12768	13671	15218	158305.5
Energy Av MW	20822	20585	19123	16951	16107	16639	16909	17026	16224	17161	18988	20454	18071.4
*L.F. %	79.0	82.1	79.0	79.0	78.5	78.4	77.5	77.0	80.9	80.0	79.0	77.0	78.9

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995													
20 Min Peak MW	27145	25679	24866	21958	21034	21732	22314	22615	20540	21974	24641	27156	23471.0
1 Hour Peak MW	26855	25518	24644	21782	20873	21602	22191	22497	20375	21725	24410	26979	23287.5
Energy GWH	15833	14135	14529	12443	12231	12226	12038	12923	11909	12994	13926	15506	161492.4
Energy Av MW	21281	21034	19528	17283	16440	16980	17256	17370	16540	17465	19342	20841	18435.2
*L.F. %	79.2	82.4	79.2	79.3	78.8	78.6	77.8	77.2	81.2	80.4	79.2	77.2	79.2
1996													
20 Min Peak MW	27618	26130	25313	22337	21459	22193	22809	23136	21008	22448	25223	27843	23959.8
1 Hour Peak MW	27321	25964	25085	22156	21294	22059	22683	23014	20837	22191	24984	27663	23770.9
Energy GWH	16237	14491	14911	12771	12578	12582	13223	13320	12280	13391	14371	16020	166176.0
Energy Av MW	21825	21564	20042	17737	16906	17475	17773	17904	17056	17999	19960	21532	18969.9
*L.F. %	79.9	83.1	79.9	80.1	79.4	79.2	78.4	77.8	81.9	81.1	79.9	77.8	79.8
1997 **													
20 Min Peak MW	28297	26730	25859	22763	21899	22633	23245	23559	21351	22741	25562	28220	24405.4
1 Hour Peak MW	27990	26559	25623	22576	21728	22495	23115	23433	21177	22478	25318	28037	24210.9
Energy GWH	16602	14813	15206	12998	12810	12805	13447	13532	12460	13553	14542	16203	168970.0
Energy Av MW	22314	22043	20438	18052	17218	17785	18074	18188	17306	18216	20197	21779	19288.8
*L.F. %	79.7	83.0	79.8	80.0	79.2	79.1	78.2	77.6	81.7	81.0	79.8	77.7	79.7
1998 **													
20 Min Peak MW	28692	27090	26198	23029	22215	22968	23595	23917	21658	23013	25901	28621	24741.4
1 Hour Peak MW	28378	26918	25957	22837	22040	22827	23461	23789	21479	22743	25651	28435	24542.7
Energy GWH	16885	15065	15457	13198	13032	13030	13683	13771	12676	13764	14779	16476	171816.9
Energy Av MW	22695	22419	20776	18331	17516	18097	18391	18510	17605	18500	20526	22145	19613.8
*L.F. %	80.0	83.3	80.0	80.3	79.5	79.3	78.4	77.8	82.0	81.3	80.0	77.9	79.9
1999 **													
20 Min Peak MW	29110	27469	26557	23312	22551	23322	23964	24295	21984	23299	26256	29039	25096.5
1 Hour Peak MW	28788	27290	26310	23116	22372	23177	23828	24163	21800	23023	25999	28851	24893.1
Energy GWH	17174	15319	15709	13403	13257	13257	13922	14012	12893	13975	15016	16749	174685.0
Energy Av MW	23083	22797	21114	18615	17818	18412	18712	18833	17907	18783	20855	22512	19941.2
*L.F. %	80.2	83.5	80.3	80.5	79.6	79.4	78.5	77.9	82.1	81.6	80.2	78.0	80.1
2000 **													
20 Min Peak MW	29536	27853	26916	23594	22882	23667	24320	24653	22289	23559	26577	29404	25437.5
1 Hour Peak MW	29207	27670	26663	23394	22699	23519	24180	24519	22102	23277	26315	29214	25229.8
Energy GWH	17443	15527	15941	13585	13458	13459	14133	14223	13083	14151	15215	16977	177199.0
Energy Av MW	23444	23106	21426	18869	18089	18694	18997	19117	18171	19020	21132	22819	20228.2
*L.F. %	80.3	83.5	80.4	80.7	79.7	79.5	78.6	78.0	82.2	81.7	80.3	78.1	80.2

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2001 ****													
20 Min Peak MW	29911	28183	27217	23821	23149	23940	24596	24925	22510	23731	26789	29650	25701.8
1 Hour Peak MW	29575	27996	26959	23617	22963	23790	24454	24788	22320	23444	26523	29458	25490.6
Energy GWH	17615	15706	16085	13695	13591	13592	14272	14363	13205	14260	15342	17124	179848.1
Energy Av MW	23676	23373	21619	19021	18267	18878	19183	19304	18340	19167	21308	23016	20416.5
*L.F. %	80.1	83.5	80.2	80.5	79.5	79.4	78.4	77.9	82.2	81.8	80.3	78.1	80.1
2002 **													
20 Min Peak MW	30180	28438	27469	24030	23404	24217	24895	25240	22791	23999	27126	30054	25986.8
1 Hour Peak MW	29839	28248	27207	23822	23215	24064	24750	25100	22597	23707	26855	29860	25771.9
Energy GWH	17839	15910	16291	13864	13776	13785	14478	14572	13398	14455	15564	17383	181315.9
Energy Av MW	23978	23676	21897	19255	18517	19146	19460	19586	18608	19429	21617	23364	20698.2
*L.F. %	80.4	83.8	80.5	80.8	79.8	79.6	78.6	78.0	82.3	82.0	80.5	78.2	80.3
2003 **													
20 Min Peak MW	30604	28836	27858	24359	23765	24601	25299	25660	23168	24372	27573	30573	26389.2
1 Hour Peak MW	30256	28643	27591	24147	23571	24445	25152	25517	22970	24074	27297	30374	26170.0
Energy GWH	18146	16183	16566	14093	14018	14029	14735	14833	13638	14702	15839	17694	184477.0
Energy Av MW	24390	24082	22266	19574	18842	19485	19805	19937	18941	19760	21998	23782	21059.0
*L.F. %	80.6	84.1	80.7	81.1	79.9	79.7	78.7	78.1	82.5	82.1	80.6	78.3	80.5
2004													
20 Min Peak MW	31140	29341	28347	24779	24204	25063	25780	26152	23609	24817	28095	31165	26874.4
1 Hour Peak MW	30785	29143	28075	24562	24006	24904	25629	26007	23407	24513	27812	30964	26650.5
Energy GWH	18487	16447	16878	14356	14289	14304	15027	15129	13910	14990	16156	18055	188026.1
Energy Av MW	24848	24475	22686	19938	19205	19867	20198	20335	19319	20148	22438	24267	21464.2
*L.F. %	80.7	84.0	80.8	81.2	80.0	79.8	78.8	78.2	82.5	82.2	80.7	78.4	80.5
2005													
20 Min Peak MW	31745	29906	28889	25243	24671	25547	26277	26655	24057	25272	28618	31751	27385.7
1 Hour Peak MW	31382	29704	28610	25021	24469	25384	26123	26506	23850	24961	28329	31545	27157.0
Energy GWH	18833	16797	17189	14614	14554	14568	15304	15407	14164	15254	16443	18379	191505.0
Energy Av MW	25313	24995	23103	20297	19562	20233	20570	20709	19672	20503	22838	24703	21861.3
*L.F. %	80.7	84.1	80.8	81.1	79.9	79.7	78.7	78.1	82.5	82.1	80.6	78.3	80.5
2006													
20 Min Peak MW	32348	30477	29443	25725	25159	26057	26809	27199	24551	25785	29208	32414	27931.1
1 Hour Peak MW	31977	30270	29159	25499	24953	25891	26652	27047	24340	25467	28913	32204	27697.6
Energy GWH	19206	17132	17533	14906	14852	14871	15624	15733	14464	15576	16795	18775	195469.8
Energy Av MW	25815	25493	23566	20703	19963	20654	21000	21146	20089	20936	23326	25236	22313.9
*L.F. %	80.7	84.2	80.8	81.2	80.0	79.8	78.8	78.2	82.5	82.2	80.7	78.4	80.6

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2007													
20 Min Peak MW	33011	31087	30021	26215	25637	26544	27299	27685	24978	26213	29686	32936	28442.6
1 Hour Peak MW	32633	30876	29731	25985	25427	26374	27139	27531	24763	25890	29386	32723	28204.8
Energy GWH	19555	17436	17835	15157	15101	15115	15875	15978	14686	15803	17034	19037	198609.9
Energy Av MW	26284	25947	23971	21051	20297	20993	21337	21476	20397	21241	23659	25587	22672.4
*L.F. %	80.5	84.0	80.6	81.0	79.8	79.6	78.6	78.0	82.4	82.0	80.5	78.2	80.4
2008													
20 Min Peak MW	33546	31590	30508	26640	26060	26982	27751	28146	25393	26644	30180	33487	28910.6
1 Hour Peak MW	33161	31375	30213	26405	25846	26810	27588	27989	25175	26316	29874	33270	28668.5
Energy GWH	19881	17678	18133	15411	15356	15372	16143	16250	14936	16073	17326	19363	201921.0
Energy Av MW	26722	26307	24372	21404	20639	21350	21698	21842	20745	21603	24063	26026	23050.3
*L.F. %	80.6	83.8	80.7	81.1	79.9	79.6	78.6	78.0	82.4	82.1	80.6	78.2	80.4
2009													
20 Min Peak MW	34122	32146	31058	27131	26552	27502	28298	28711	25916	27206	30826	34218	29473.7
1 Hour Peak MW	33730	31928	30757	26892	26334	27326	28132	28551	25693	26870	30515	33996	29227.0
Energy GWH	20259	18071	18493	15724	15675	15698	16491	16607	15271	16438	17726	19817	206267.9
Energy Av MW	27229	26892	24856	21839	21068	21802	22166	22321	21209	22095	24619	26636	23546.6
*L.F. %	80.7	84.2	80.8	81.2	80.0	79.8	78.8	78.2	82.5	82.2	80.7	78.3	80.6
2010													
20 Min Peak MW	34864	32845	31730	27719	27122	28090	28902	29321	26466	27784	31477	34935	30104.4
1 Hour Peak MW	34463	32622	31423	27475	26900	27910	28733	29157	26239	27441	31159	34709	29852.6
Energy GWH	20688	18453	18882	16055	16003	16026	16834	16951	15587	16779	18090	20222	210572.0
Energy Av MW	27807	27459	25380	22299	21510	22258	22626	22784	21648	22552	25125	27180	24037.9
*L.F. %	80.7	84.2	80.8	81.2	80.0	79.8	78.7	78.1	82.5	82.2	80.6	78.3	80.5
2011													
20 Min Peak MW	35594	33528	32386	28290	27674	28655	29478	29901	26988	28327	32087	35606	30709.7
1 Hour Peak MW	35186	33301	32073	28041	27447	28472	29306	29735	26756	27978	31763	35375	30452.8
Energy GWH	21097	18815	19251	16367	16313	16332	17152	17270	15878	17091	18422	20589	214576.8
Energy Av MW	28356	27999	25875	22732	21926	22684	23054	23212	22053	22972	25586	27674	24495.1
*L.F. %	80.6	84.1	80.7	81.1	79.9	79.7	78.7	78.1	82.4	82.1	80.6	78.2	80.4
2012													
20 Min Peak MW	36281	34176	33012	28839	28207	29206	30044	30474	27506	28873	32703	36284	31301.1
1 Hour Peak MW	35865	33944	32693	28586	27976	29020	29868	30304	27270	28518	32373	36050	31039.0
Energy GWH	21496	19170	19613	16678	16620	16641	17476	17594	16177	17413	18768	20975	218624.0
Energy Av MW	28893	28527	26362	23164	22338	23112	23489	23648	22468	23405	26067	28192	24957.1
*L.F. %	80.6	84.0	80.6	81.0	79.8	79.6	78.6	78.0	82.4	82.1	80.5	78.2	80.4

* Load Factor based on 1-Hour Peak

TOTAL SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

2013	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
20 Min Peak MW	36984	34845	33664	29416	28769	29792	30650	31092	28070	29476	33385	37043	31932.0
1 Hour Peak MW	36560	34609	33339	29158	28534	29602	30470	30918	27829	29113	33048	36803	31665.3
Energy GWH	21920	19551	20007	17016	16958	16981	17836	17958	16516	17782	19165	21420	223110.0
Energy Av MW	29462	29094	26891	23634	22794	23585	23973	24137	22938	23901	26618	28791	25469.2
*L.F. %	80.6	84.1	80.7	81.1	79.9	79.7	78.7	78.1	82.4	82.1	80.5	78.2	80.4
2014													
20 Min Peak MW	37763	35586	34387	30058	29395	30445	31325	31781	28701	30149	34147	37890	32635.6
1 Hour Peak MW	37331	35345	34055	29794	29155	30251	31142	31605	28455	29779	33803	37646	32363.4
Energy GWH	22391	19975	20445	17394	17335	17362	18237	18366	16893	18195	19610	21919	228120.0
Energy Av MW	30095	29725	27479	24158	23300	24114	24512	24685	23463	24455	27237	29461	26041.1
*L.F. %	80.6	84.1	80.7	81.1	79.9	79.7	78.7	78.1	82.5	82.1	80.6	78.3	80.5
2015													
20 Min Peak MW	38622	36394	35165	30740	30051	31119	32014	32476	29328	30810	34886	38700	33358.8
1 Hour Peak MW	38181	36148	34826	30470	29806	30921	31827	32295	29077	30432	34535	38452	33080.8
Energy GWH	22875	20403	20881	17766	17702	17726	18616	18748	17244	18571	20012	22364	232908.0
Energy Av MW	30746	30362	28066	24675	23794	24620	25022	25199	23949	24961	27794	30059	26587.7
*L.F. %	80.5	84.0	80.6	81.0	79.8	79.6	78.6	78.0	82.4	82.0	80.5	78.2	80.4

* Load Factor based on 1-Hour Peak

NOTE
For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP,TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1989													
20 Min Peak MW	22563	21497	20904	18704	17796	18315	18756	19044	17418	18690	20770	22809	19772.2
1 Hour Peak MW	22328	21363	20725	18559	17663	18207	18652	18943	17278	18489	20579	22660	19620.5
Energy GWH	12827	11483	11905	10246	10016	9970	10450	10544	9750	10687	11390	12552	131820.0
Energy Av MW	17241	17088	16001	14231	13462	13847	14046	14172	13542	14364	15819	16871	15047.9
*L.F. %	77.2	80.0	77.2	76.7	76.2	76.1	75.3	74.8	78.4	77.7	76.9	74.5	76.7
1990													
20 Min Peak MW	23274	22134	21450	19075	18146	18694	19194	19385	17676	18974	21179	23275	20204.7
1 Hour Peak MW	23032	21998	21266	18927	18011	18584	19089	19283	17534	18770	20984	23103	20048.4
Energy GWH	13272	11868	12246	10472	10236	10204	10711	10764	9935	10893	11658	12880	135137.8
Energy Av MW	17839	17661	16460	14544	13758	14172	14397	14468	13799	14641	16192	17312	15426.7
*L.F. %	77.5	80.3	77.4	76.8	76.4	76.3	75.4	75.0	78.7	78.0	77.2	74.9	76.9
1991													
20 Min Peak MW	23808	22592	21887	19473	18574	19116	19632	19911	18125	19412	21683	23929	20678.4
1 Hour Peak MW	23557	22452	21696	19321	18434	19003	19524	19806	17980	19199	21481	23773	20518.8
Energy GWH	13592	12142	12529	10729	10518	10472	10996	11082	10214	11166	11953	13255	138649.6
Energy Av MW	18269	18068	16840	14901	14137	14544	14780	14895	14186	15008	16601	17816	15827.6
*L.F. %	77.6	80.5	77.6	77.1	76.7	76.5	75.7	75.2	78.9	78.2	77.3	74.9	77.1
1992													
20 Min Peak MW	24527	23272	22524	20004	19089	19672	20220	20496	18622	19940	22304	24593	21272.0
1 Hour Peak MW	24266	23126	22326	19846	18944	19555	20107	20387	18472	19719	22094	24431	21106.1
Energy GWH	14032	12982	12914	11047	10830	10803	11358	11437	10527	11507	12331	13714	143481.7
Energy Av MW	18860	18652	17358	15343	14556	15004	15266	15372	14621	15466	17126	18433	16334.4
*L.F. %	77.7	83.5	77.7	77.3	76.8	76.7	75.9	75.4	79.2	78.4	77.5	75.4	77.6
1993													
20 Min Peak MW	25128	23815	23048	20424	19495	20094	20670	20951	19000	20349	22813	25170	21746.4
1 Hour Peak MW	24859	23666	22842	20261	19347	19974	20555	20840	18845	20121	22598	25003	21575.9
Energy GWH	14448	12905	13285	11350	11126	11100	11680	11756	10807	11813	12679	14129	147078.1
Energy Av MW	19419	19204	17856	15764	14954	15417	15699	15801	15010	15878	17610	18991	16789.7
*L.F. %	78.1	81.1	78.2	77.8	77.3	77.2	76.4	75.8	79.6	78.9	77.9	76.0	77.8
1994													
20 Min Peak MW	25611	24255	23465	20753	19837	20461	21068	21355	19342	20706	23256	25691	22150.0
1 Hour Peak MW	25334	24104	23254	20588	19687	20341	20953	21243	19186	20472	23036	25522	21976.7
Energy GWH	14794	13213	13591	11597	11377	11357	11960	12034	11061	12091	12991	14497	150563.0
Energy Av MW	19884	19662	18267	16107	15292	15774	16075	16175	15363	16251	18043	19485	17187.6
*L.F. %	78.5	81.6	78.6	78.2	77.7	77.5	76.7	76.1	80.1	79.4	78.3	76.3	78.2

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995 **													
20 Min Peak MW	26168	24761	23939	21137	20237	20872	21490	21778	19701	21046	23660	26153	22578.5
1 Hour Peak MW	25883	24603	23721	20967	20081	20748	21372	21664	19540	20805	23433	25979	22399.7
Energy GWH	15119	13499	13875	11826	11612	11590	12202	12274	11275	12305	13226	14762	153565.4
Energy Av MW	20322	20088	18650	16425	15607	16098	16400	16497	15659	16539	18370	19841	17530.3
*L.F. %	78.5	81.6	78.6	78.3	77.7	77.6	76.7	76.2	80.1	79.5	78.4	76.4	78.3
1996													
20 Min Peak MW	26625	25198	24371	21506	20650	21319	21973	22286	20155	21507	24227	26827	23053.8
1 Hour Peak MW	26332	25037	24147	21332	20489	21191	21850	22168	19989	21258	23992	26651	22869.8
Energy GWH	15506	13841	14243	12139	11943	11931	12571	12655	11630	12685	13654	15258	158054.7
Energy Av MW	20841	20596	19144	16859	16052	16570	16897	17009	16152	17050	18964	20508	18042.8
*L.F. %	79.1	82.3	79.3	79.0	78.3	78.2	77.3	76.7	80.8	80.2	79.0	76.9	78.9
1997 **													
20 Min Peak MW	27289	25786	24905	21922	21076	21744	22393	22693	20483	21787	24550	27185	23484.5
1 Hour Peak MW	26986	25619	24673	21742	20911	21612	22267	22572	20312	21532	24310	27007	23295.4
Energy GWH	15853	14146	14522	12350	12160	12137	12777	12850	11793	12829	13807	15422	160645.7
Energy Av MW	21308	21051	19519	17153	16344	16857	17174	17271	16379	17244	19177	20729	18338.6
*L.F. %	79.0	82.2	79.1	78.9	78.2	78.0	77.1	76.5	80.6	80.1	78.9	76.8	78.7
1998 **													
20 Min Peak MW	27665	26126	25225	22172	21374	22058	22723	23031	20770	22037	24865	27562	23800.6
1 Hour Peak MW	27354	25955	24988	21988	21205	21923	22594	22906	20595	21776	24619	27381	23607.0
Energy GWH	16118	14381	14755	12535	12363	12343	12996	13070	11990	13021	14024	15673	163267.5
Energy Av MW	21663	21401	19832	17410	16617	17144	17467	17567	16652	17501	19478	21065	18637.8
*L.F. %	79.2	82.5	79.4	79.2	78.4	78.2	77.3	76.7	80.9	80.4	79.1	76.9	79.0
1999 **													
20 Min Peak MW	28058	26485	25562	22439	21689	22390	23071	23386	21072	22302	25197	27956	24133.9
1 Hour Peak MW	27741	26310	25319	22250	21516	22252	22939	23259	20893	22035	24945	27773	23936.0
Energy GWH	16385	14618	14989	12722	12571	12552	13216	13291	12189	13212	14241	15925	165909.5
Energy Av MW	22023	21752	20147	17670	16896	17433	17763	17864	16929	17758	19780	21404	18939.4
*L.F. %	79.4	82.7	79.6	79.4	78.5	78.3	77.4	76.8	81.0	80.6	79.3	77.1	79.1
2000 ****													
20 Min Peak MW	28462	26848	25899	22702	22000	22712	23404	23722	21355	22542	25494	28296	24453.0
1 Hour Peak MW	28137	26669	25651	22510	21822	22571	23269	23592	21173	22270	25237	28110	24250.9
Energy GWH	16634	14809	15203	12888	12754	12735	13409	13483	12359	13370	14421	16132	168195.7
Energy Av MW	22357	22037	20434	17900	17142	17687	18023	18122	17165	17971	20029	21683	19200.4
*L.F. %	79.5	82.6	79.7	79.5	78.6	78.4	77.5	76.8	81.1	80.7	79.4	77.1	79.2

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2001 ****													
20 Min Peak MW	28692	27051	26087	22839	22185	22908	23610	23932	21528	22672	25669	28511	24640.4
1 Hour Peak MW	28362	26869	25835	22643	22005	22765	23473	23800	21343	22395	25408	28324	24435.3
Energy GWH	16786	14969	15329	12981	12868	12850	13529	13603	12462	13459	14528	16258	169622.0
Energy Av MW	22561	22276	20604	18029	17296	17847	18184	18284	17309	18090	20178	21852	19363.2
*L.F. %	79.5	82.9	79.8	79.6	78.6	78.4	77.5	76.8	81.1	80.8	79.4	77.2	79.2
2002 **													
20 Min Peak MW	28983	27322	26350	23054	22440	23180	23900	24234	21792	22919	25979	28881	24919.5
1 Hour Peak MW	28647	27137	26094	22855	22256	23035	23761	24099	21603	22637	25713	28691	24710.7
Energy GWH	16989	15154	15516	13131	13034	13021	13714	13792	12634	13632	14727	16492	171835.5
Energy Av MW	22835	22550	20854	18237	17519	18085	18432	18537	17548	18323	20455	22166	19615.9
*L.F. %	79.7	83.1	79.9	79.8	78.7	78.5	77.6	76.9	81.2	80.9	79.5	77.3	79.4
2003 **													
20 Min Peak MW	29438	27746	26758	23395	22806	23564	24302	24644	22153	23274	26401	29365	25320.4
1 Hour Peak MW	29095	27558	26496	23192	22618	23415	24159	24507	21961	22986	26129	29172	25107.2
Energy GWH	17273	15406	15771	13340	13255	13244	13951	14031	12853	13857	14979	16779	174738.8
Energy Av MW	23216	22926	21197	18528	17816	18395	18751	18859	17851	18624	20804	22552	19947.4
*L.F. %	79.8	83.2	80.0	79.9	78.8	78.6	77.6	77.0	81.3	81.0	79.6	77.3	79.4
2004 **													
20 Min Peak MW	29940	28218	27215	23786	23215	23993	24751	25105	22565	23687	26887	29921	25773.6
1 Hour Peak MW	29590	28026	26948	23579	23024	23842	24605	24965	22368	23393	26610	29725	25556.2
Energy GWH	17589	15650	16060	13582	13505	13497	14220	14304	13103	14121	15272	17114	178015.3
Energy Av MW	23640	23289	21586	18864	18152	18745	19113	19226	18198	18979	21211	23002	20321.4
*L.F. %	79.9	83.1	80.1	80.0	78.8	78.6	77.7	77.0	81.4	81.1	79.7	77.4	79.5
2005 **													
20 Min Peak MW	30508	28749	27722	24220	23652	24444	25216	25575	22981	24107	27373	30467	26251.0
1 Hour Peak MW	30151	28552	27449	24008	23457	24289	25068	25432	22780	23807	27090	30267	26029.0
Energy GWH	17910	15975	16348	13819	13747	13738	14474	14559	13334	14360	15535	17410	181209.0
Energy Av MW	24073	23773	21973	19193	18477	19081	19454	19568	18519	19302	21576	23400	20686.0
*L.F. %	79.8	83.3	80.1	79.9	78.8	78.6	77.6	76.9	81.3	81.1	79.6	77.3	79.5
2006													
20 Min Peak MW	31072	29281	28239	24669	24106	24919	25711	26082	23437	24580	27920	31086	26758.6
1 Hour Peak MW	30707	29080	27960	24452	23907	24761	25560	25936	23232	24274	27631	30882	26531.9
Energy GWH	18257	16286	16667	14087	14021	14015	14768	14858	13609	14655	15857	17776	184854.8
Energy Av MW	24538	24235	22402	19565	18845	19466	19849	19970	18901	19697	22024	23893	21102.1
*L.F. %	79.9	83.3	80.1	80.0	78.8	78.6	77.7	77.0	81.4	81.1	79.7	77.4	79.5

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2007 **													
20 Min Peak MW	31691	29850	28774	25123	24547	25367	26163	26529	23827	24969	28354	31560	27229.7
1 Hour Peak MW	31318	29645	28490	24902	24344	25205	26008	26381	23618	24657	28060	31353	26998.6
Energy GWH	18576	16564	16942	14313	14243	14233	14992	15076	13803	14853	16067	18006	187667.4
Energy Av MW	24968	24649	22772	19879	19144	19767	20150	20264	19171	19963	22316	24202	21423.2
*L.F. %	79.7	83.1	79.9	79.8	78.6	78.4	77.5	76.8	81.2	81.0	79.5	77.2	79.3
2008 **													
20 Min Peak MW	32176	30308	29216	25507	24931	25765	26574	26949	24203	25358	28801	32061	27654.2
1 Hour Peak MW	31798	30099	28927	25282	24724	25601	26418	26797	23990	25041	28502	31851	27419.2
Energy GWH	18871	16781	17212	14539	14472	14462	15234	15321	14027	15093	16329	18301	190640.9
Energy Av MW	25364	24972	23135	20194	19451	20086	20476	20592	19482	20286	22679	24598	21762.7
*L.F. %	79.8	83.0	80.0	79.9	78.7	78.5	77.5	76.8	81.2	81.0	79.6	77.2	79.4
2009													
20 Min Peak MW	32704	30816	29720	25958	25383	26244	27080	27472	24684	25875	29401	32742	28173.2
1 Hour Peak MW	32319	30604	29426	25729	25173	26077	26921	27318	24468	25551	29096	32527	27934.0
Energy GWH	19217	17145	17543	14825	14763	14759	15553	15648	14333	15427	16698	18721	194634.6
Energy Av MW	25830	25513	23580	20591	19843	20499	20905	21033	19907	20736	23191	25163	22218.6
*L.F. %	79.9	83.4	80.1	80.0	78.8	78.6	77.7	77.0	81.4	81.2	79.7	77.4	79.5
2010													
20 Min Peak MW	33395	31467	30346	26504	25913	26789	27640	28039	25193	26408	30002	33408	28758.6
1 Hour Peak MW	33002	31251	30046	26271	25699	26618	27477	27882	24972	26078	29691	33189	28514.6
Energy GWH	19614	17497	17903	15129	15064	15059	15867	15963	14620	15736	17030	19093	198577.5
Energy Av MW	26363	26037	24064	21013	20248	20915	21327	21456	20306	21151	23653	25663	22668.7
*L.F. %	79.9	83.3	80.1	80.0	78.8	78.6	77.6	77.0	81.3	81.1	79.7	77.3	79.5
2011 **													
20 Min Peak MW	34073	32101	30952	27030	26421	27308	28171	28573	25669	26904	30559	34022	29315.3
1 Hour Peak MW	33672	31881	30646	26793	26202	27135	28005	28413	25444	26569	30242	33799	29066.8
Energy GWH	19990	17830	18241	15411	15343	15334	16155	16250	14881	16015	17328	19424	202201.5
Energy Av MW	26868	26532	24517	21405	20623	21298	21714	21841	20668	21526	24067	26107	23082.4
*L.F. %	79.8	83.2	80.0	79.9	78.7	78.5	77.5	76.9	81.2	81.0	79.6	77.2	79.4
2012 **													
20 Min Peak MW	34706	32697	31527	27535	26909	27813	28691	29098	26142	27402	31122	34644	29856.9
1 Hour Peak MW	34298	32473	31215	27293	26687	27636	28522	28935	25913	27060	30799	34417	29603.8
Energy GWH	20353	18153	18571	15692	15620	15612	16447	16543	15148	16303	17639	19772	205853.7
Energy Av MW	27357	27013	24961	21794	20995	21683	22106	22235	21039	21913	24499	26575	23499.3
*L.F. %	79.8	83.2	80.0	79.9	78.7	78.5	77.5	76.8	81.2	81.0	79.5	77.2	79.4

* Load Factor based on 1-Hour Peak

EAST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2013 **													
20 Min Peak MW	35349	33309	32123	28062	27424	28348	29247	29667	26658	27952	31747	35343	30435.7
1 Hour Peak MW	34933	33081	31806	27816	27198	28168	29075	29500	26424	27604	31418	35111	30177.8
Energy GWH	20741	18501	18931	15999	15927	15920	16774	16874	15455	16637	18002	20179	209939.4
Energy Av MW	27877	27532	25445	22221	21408	22111	22545	22680	21465	22362	25002	27123	23965.7
*L.F. %	79.8	83.2	80.0	79.9	78.7	78.5	77.5	76.9	81.2	81.0	79.6	77.2	79.4
2014													
20 Min Peak MW	36069	33996	32792	28655	28004	28951	29874	30307	27241	28574	32455	36133	31087.7
1 Hour Peak MW	35645	33763	32469	28404	27773	28768	29698	30138	27003	28219	32119	35896	30824.7
Energy GWH	21175	18893	19335	16345	16272	16267	17142	17248	15799	17014	18410	20640	214539.9
Energy Av MW	28461	28114	25988	22701	21871	22593	23040	23182	21943	22868	25570	27742	24490.9
*L.F. %	79.8	83.3	80.0	79.9	78.8	78.5	77.6	76.9	81.3	81.0	79.6	77.3	79.5
2015													
20 Min Peak MW	36870	34749	33516	29289	28613	29575	30513	30951	27820	29182	33135	36883	31758.0
1 Hour Peak MW	36438	34511	33185	29032	28377	29388	30334	30778	27577	28820	32793	36641	31489.5
Energy GWH	21621	19287	19738	16685	16607	16599	17489	17595	16116	17354	18775	21046	218909.4
Energy Av MW	29060	28701	26529	23173	22321	23054	23507	23649	22383	23325	26076	28287	24989.7
*L.F. %	79.8	83.2	79.9	79.8	78.7	78.4	77.5	76.8	81.2	80.9	79.5	77.2	79.4

* Load Factor based on 1-Hour Peak

NOTE
For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP,TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1989													
20 Min Peak MW	1094	1070	1016	962	928	911	917	902	953	1000	1025	1080	988.0
1 Hour Peak MW	1090	1065	1012	956	923	906	913	899	948	994	1021	1076	983.6
Energy GWH	675	609	618	590	593	580	583	594	584	638	627	672	7362.8
Energy Av MW	907	906	831	819	797	806	784	798	811	858	871	903	840.5
*L.F. %	83.2	85.1	82.1	85.7	86.4	88.9	85.8	88.8	85.6	86.3	85.3	83.9	85.5
1990													
20 Min Peak MW	1103	1065	1022	968	922	942	943	925	978	1022	1071	1128	1007.3
1 Hour Peak MW	1100	1060	1018	962	916	937	940	922	974	1016	1068	1123	1003.0
Energy GWH	688	613	628	599	595	607	608	618	606	660	667	710	7600.2
Energy Av MW	925	912	844	832	800	843	817	831	842	887	926	954	867.6
*L.F. %	84.1	86.1	82.9	86.5	87.3	90.0	86.9	90.1	86.4	87.3	86.7	85.0	86.5
1991													
20 Min Peak MW	1115	1075	1040	978	931	957	960	945	999	1048	1100	1161	1025.9
1 Hour Peak MW	1112	1070	1036	971	925	951	956	941	994	1042	1096	1156	1020.8
Energy GWH	702	625	644	612	608	624	625	638	625	684	692	737	7817.4
Energy Av MW	944	930	866	850	817	867	840	858	868	919	961	991	892.4
*L.F. %	84.9	86.9	83.6	87.5	88.3	91.1	87.9	91.1	87.3	88.2	87.7	85.7	87.4
1992													
20 Min Peak MW	1132	1090	1054	990	943	971	974	957	1012	1060	1111	1170	1038.6
1 Hour Peak MW	1129	1085	1050	983	937	966	970	953	1007	1053	1107	1165	1033.8
Energy GWH	720	664	660	626	624	641	642	655	640	700	707	751	8028.3
Energy Av MW	968	954	887	869	839	890	863	880	889	941	982	1009	914.0
*L.F. %	85.7	91.1	84.5	88.4	89.5	92.2	89.0	92.4	88.3	89.4	88.7	86.6	88.7
1993													
20 Min Peak MW	1085	1044	1008	945	899	926	928	912	964	1009	1058	1112	990.9
1 Hour Peak MW	1082	1040	1004	939	895	922	924	909	959	1002	1054	1108	986.5
Energy GWH	692	616	634	600	599	614	614	627	612	669	675	717	7669.9
Energy Av MW	930	917	852	833	805	853	825	843	850	899	938	964	875.6
*L.F. %	86.0	88.1	84.9	88.7	90.0	92.5	89.3	92.7	88.6	89.7	88.9	87.0	88.8
1994													
20 Min Peak MW	1086	1043	1007	942	897	924	926	909	962	1004	1055	1112	988.9
1 Hour Peak MW	1083	1039	1002	935	893	919	922	905	957	997	1051	1107	984.2
Energy GWH	702	624	641	606	605	620	620	632	617	673	680	723	7741.7
Energy Av MW	944	929	862	842	813	861	833	849	857	905	944	972	883.8
*L.F. %	87.1	89.4	86.0	90.0	91.1	93.7	90.4	93.9	89.5	90.7	89.9	87.8	89.8

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
1995													
20 Min Peak MW	1098	1056	1020	954	912	941	945	928	985	1026	1081	1142	1007.5
1 Hour Peak MW	1094	1050	1016	946	906	935	940	924	979	1018	1077	1137	1002.0
Energy GWH	713	636	653	617	619	635	636	649	634	689	700	744	7927.0
Energy Av MW	959	946	878	857	832	882	855	872	881	926	972	1000	904.9
*L.F. %	87.7	90.1	86.5	90.6	91.8	94.3	90.9	94.4	90.0	90.9	90.3	88.0	90.3
1996													
20 Min Peak MW	1116	1073	1036	968	928	958	962	945	1003	1042	1099	1161	1024.4
1 Hour Peak MW	1112	1067	1032	961	922	952	957	940	998	1034	1095	1156	1018.9
Energy GWH	731	650	668	632	635	651	652	666	651	706	717	762	8121.3
Energy Av MW	983	968	898	878	853	904	876	895	904	949	996	1024	927.1
*L.F. %	88.4	90.7	87.0	91.3	92.5	95.0	91.5	95.2	90.6	91.7	91.0	88.6	91.0
1997													
20 Min Peak MW	1137	1092	1053	984	947	978	980	963	1023	1061	1119	1184	1043.4
1 Hour Peak MW	1132	1086	1049	976	940	971	976	958	1018	1052	1115	1178	1037.5
Energy GWH	749	667	684	647	650	668	669	682	668	723	735	781	8324.3
Energy Av MW	1006	992	920	899	874	928	900	917	927	972	1021	1050	950.3
*L.F. %	88.9	91.4	87.6	92.2	93.0	95.6	92.1	95.7	91.1	92.4	91.6	89.2	91.6
1998													
20 Min Peak MW	1158	1112	1073	1001	967	999	1002	985	1047	1083	1143	1209	1064.9
1 Hour Peak MW	1154	1107	1068	993	961	992	998	980	1041	1074	1138	1204	1059.2
Energy GWH	768	684	702	663	669	686	688	702	686	743	755	803	8549.4
Energy Av MW	1032	1018	944	921	899	953	924	943	953	999	1048	1080	976.0
*L.F. %	89.4	92.0	88.4	92.7	93.6	96.1	92.6	96.2	91.5	93.0	92.1	89.7	92.1
1999													
20 Min Peak MW	1184	1136	1095	1022	990	1022	1027	1008	1073	1106	1168	1236	1089.0
1 Hour Peak MW	1180	1130	1090	1014	983	1015	1022	1003	1067	1096	1163	1230	1082.8
Energy GWH	789	702	720	681	686	705	706	721	705	762	774	824	8775.5
Energy Av MW	1060	1044	968	945	922	979	949	969	979	1025	1075	1108	1001.8
*L.F. %	89.9	92.4	88.8	93.2	93.8	96.4	92.8	96.6	91.8	93.5	92.5	90.1	92.5
2000													
20 Min Peak MW	1210	1160	1119	1042	1013	1047	1051	1032	1098	1129	1194	1264	1113.2
1 Hour Peak MW	1205	1153	1114	1034	1006	1040	1046	1027	1092	1119	1189	1258	1106.9
Energy GWH	809	719	738	698	705	724	725	740	724	781	794	845	9001.3
Energy Av MW	1087	1069	992	969	947	1006	974	995	1006	1050	1103	1136	1027.5
*L.F. %	90.2	92.7	89.0	93.7	94.2	96.8	93.1	96.9	92.1	93.8	92.8	90.3	92.8

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2001													
20 Min Peak MW	1237	1186	1144	1065	1038	1073	1077	1057	1126	1155	1221	1294	1139.5
1 Hour Peak MW	1232	1180	1139	1056	1030	1065	1072	1052	1120	1145	1216	1287	1132.9
Energy GWH	829	737	755	714	723	743	744	760	742	801	814	866	9227.1
Energy Av MW	1114	1097	1015	992	971	1031	999	1021	1031	1076	1131	1164	1053.3
*L.F. %	90.5	92.9	89.1	93.9	94.3	96.8	93.2	97.0	92.1	94.0	93.0	90.4	93.0
2002													
20 Min Peak MW	1266	1214	1171	1091	1065	1101	1106	1086	1157	1185	1254	1330	1168.8
1 Hour Peak MW	1261	1208	1166	1082	1058	1094	1101	1081	1150	1175	1249	1323	1162.3
Energy GWH	850	757	776	733	742	764	764	780	763	823	837	891	9480.4
Energy Av MW	1143	1126	1043	1018	998	1060	1027	1049	1060	1106	1163	1198	1082.2
*L.F. %	90.6	93.2	89.4	94.1	94.3	96.9	93.3	97.0	92.2	94.1	93.1	90.6	93.1
2003													
20 Min Peak MW	1301	1246	1201	1119	1094	1131	1137	1116	1189	1216	1287	1365	1200.1
1 Hour Peak MW	1295	1239	1196	1110	1086	1123	1132	1111	1182	1206	1282	1358	1193.2
Energy GWH	873	777	796	753	763	785	784	802	785	845	860	915	9737.2
Energy Av MW	1174	1157	1069	1046	1026	1090	1054	1077	1090	1136	1194	1229	1111.6
*L.F. %	90.7	93.3	89.4	94.2	94.5	97.0	93.2	97.0	92.2	94.2	93.1	90.5	93.2
2004													
20 Min Peak MW	1336	1281	1235	1150	1126	1164	1169	1148	1223	1250	1323	1405	1234.2
1 Hour Peak MW	1330	1274	1229	1140	1117	1155	1164	1143	1216	1240	1318	1398	1227.0
Energy GWH	898	797	818	774	784	808	807	824	807	869	884	941	10011.5
Energy Av MW	1207	1186	1100	1075	1054	1122	1085	1108	1120	1168	1228	1265	1142.9
*L.F. %	90.8	93.1	89.5	94.3	94.4	97.1	93.2	96.9	92.1	94.2	93.1	90.5	93.1
2005													
20 Min Peak MW	1373	1317	1269	1182	1158	1198	1203	1182	1259	1286	1361	1444	1269.4
1 Hour Peak MW	1368	1310	1264	1172	1150	1190	1197	1176	1252	1275	1356	1438	1262.4
Energy GWH	923	822	840	795	807	830	830	848	830	894	909	969	10296.0
Energy Av MW	1241	1223	1130	1104	1084	1152	1116	1140	1153	1201	1262	1302	1175.3
*L.F. %	90.7	93.3	89.4	94.2	94.3	96.9	93.2	97.0	92.1	94.2	93.0	90.5	93.1
2006													
20 Min Peak MW	1414	1357	1308	1218	1194	1235	1240	1219	1299	1328	1406	1491	1309.1
1 Hour Peak MW	1408	1350	1303	1208	1185	1227	1235	1213	1292	1316	1400	1484	1301.8
Energy GWH	950	846	866	819	831	855	856	875	856	922	938	999	10613.0
Energy Av MW	1277	1259	1164	1137	1117	1188	1150	1176	1188	1239	1303	1343	1211.5
*L.F. %	90.7	93.2	89.4	94.1	94.3	96.8	93.1	97.0	92.0	94.1	93.1	90.5	93.1

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2007													
20 Min Peak MW	1459	1400	1349	1257	1232	1275	1281	1258	1340	1370	1450	1538	1350.7
1 Hour Peak MW	1454	1392	1344	1247	1223	1266	1275	1252	1333	1358	1445	1532	1343.4
Energy GWH	979	872	893	844	857	882	883	902	883	951	967	1031	10944.5
Energy Av MW	1316	1298	1200	1173	1152	1226	1187	1213	1226	1278	1343	1386	1249.4
*L.F. %	90.5	93.2	89.3	94.1	94.2	96.8	93.1	96.9	91.9	94.1	92.9	90.5	93.0
2008													
20 Min Peak MW	1506	1444	1393	1297	1272	1316	1321	1298	1383	1414	1497	1587	1394.0
1 Hour Peak MW	1500	1436	1387	1286	1263	1306	1315	1292	1375	1402	1491	1581	1386.2
Energy GWH	1010	897	921	871	884	910	909	930	909	980	997	1062	11281.1
Energy Av MW	1358	1335	1238	1210	1188	1264	1222	1250	1263	1317	1385	1428	1287.8
*L.F. %	90.5	92.9	89.3	94.1	94.1	96.8	92.9	96.7	91.8	93.9	92.9	90.3	92.9
2009													
20 Min Peak MW	1554	1492	1439	1341	1313	1355	1365	1339	1409	1461	1546	1640	1439.4
1 Hour Peak MW	1548	1484	1432	1330	1304	1346	1359	1333	1421	1449	1540	1633	1431.5
Energy GWH	1041	926	950	899	911	938	938	958	938	1011	1028	1096	11634.3
Energy Av MW	1400	1379	1276	1248	1225	1303	1261	1288	1303	1359	1428	1473	1328.1
*L.F. %	90.4	92.9	89.2	93.9	93.9	96.8	92.8	96.6	91.7	93.8	92.8	90.2	92.8
2010													
20 Min Peak MW	1605	1541	1486	1384	1356	1399	1408	1382	1474	1509	1596	1692	1486.0
1 Hour Peak MW	1598	1533	1479	1373	1347	1390	1402	1376	1466	1496	1590	1685	1477.9
Energy GWH	1074	956	979	926	939	967	967	988	967	1042	1060	1129	11993.5
Energy Av MW	1443	1423	1316	1286	1262	1343	1299	1328	1342	1401	1472	1518	1369.1
*L.F. %	90.3	92.8	89.0	93.6	93.7	96.6	92.6	96.5	91.5	93.7	92.6	90.1	92.6
2011													
20 Min Peak MW	1657	1590	1534	1430	1400	1445	1455	1428	1523	1557	1649	1749	1534.8
1 Hour Peak MW	1651	1582	1527	1419	1391	1436	1448	1421	1515	1543	1642	1741	1526.4
Energy GWH	1107	985	1010	955	970	998	997	1020	997	1076	1094	1166	12375.5
Energy Av MW	1488	1466	1358	1327	1303	1386	1340	1371	1385	1446	1520	1567	1412.7
*L.F. %	90.1	92.7	88.9	93.5	93.7	96.5	92.5	96.4	91.4	93.7	92.5	90.0	92.6
2012													
20 Min Peak MW	1712	1643	1585	1478	1446	1493	1503	1475	1572	1608	1703	1806	1585.2
1 Hour Peak MW	1705	1635	1578	1466	1436	1483	1496	1469	1564	1595	1696	1798	1576.7
Energy GWH	1143	1017	1042	986	999	1029	1029	1052	1029	1110	1129	1203	12767.3
Energy Av MW	1536	1514	1401	1369	1343	1429	1383	1413	1429	1491	1568	1617	1457.5
*L.F. %	90.1	92.6	88.7	93.4	93.5	96.4	92.5	96.2	91.4	93.5	92.4	89.9	92.4

* Load Factor based on 1-Hour Peak

WEST SYSTEM ONTARIO PRIMARY DEMANDS
BASED ON LOAD FORECAST REPORT NO. 891211

	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC	AVG/TOTAL
2013													
20 Min Peak MW	1769	1698	1638	1528	1494	1542	1553	1524	1624	1662	1760	1865	1638.1
1 Hour Peak MW	1762	1689	1631	1516	1484	1532	1546	1517	1615	1648	1753	1858	1629.3
Energy GWH	1179	1050	1076	1017	1031	1062	1062	1084	1061	1145	1163	1241	13171.6
Energy Av MW	1585	1562	1446	1413	1386	1475	1427	1458	1474	1539	1616	1668	1503.6
*L.F. %	90.0	92.5	88.6	93.2	93.4	96.2	92.3	96.1	91.3	93.4	92.2	89.8	92.3
2014													
20 Min Peak MW	1826	1754	1691	1578	1542	1592	1602	1573	1676	1716	1816	1925	1691.0
1 Hour Peak MW	1819	1745	1684	1566	1531	1581	1595	1566	1667	1701	1809	1917	1681.8
Energy GWH	1216	1082	1109	1049	1063	1095	1095	1118	1094	1181	1200	1279	13581.1
Energy Av MW	1635	1611	1491	1457	1429	1520	1471	1503	1519	1587	1667	1719	1550.4
*L.F. %	89.8	92.3	88.5	93.1	93.3	96.1	92.2	96.0	91.2	93.3	92.1	89.7	92.2
2015													
20 Min Peak MW	1886	1810	1747	1629	1591	1643	1653	1623	1730	1772	1875	1987	1745.4
1 Hour Peak MW	1878	1801	1739	1616	1580	1632	1646	1616	1720	1757	1868	1978	1735.9
Energy GWH	1254	1116	1144	1082	1096	1127	1128	1153	1128	1217	1237	1318	13999.6
Energy Av MW	1685	1661	1537	1502	1473	1566	1516	1550	1566	1636	1718	1772	1598.1
*L.F. %	89.7	92.2	88.4	93.0	93.2	95.9	92.1	95.9	91.1	93.2	92.0	89.6	92.1

* Load Factor based on 1-Hour Peak

NOTE
For years marked with ** the growth of Basic Load over the course of the year is smaller than the growth in the total of EIP,TOU and load displacement NUG's impacts. As a result the January 20 Min Peak MW in those years is greater than the December 20 Min Peak MW. For years marked with **** the same holds for the 1-Hour Peak MW.

6.0 PERFORMANCE OF LOAD FORECAST 891211 in 1989

6.1 Actual Primary Demand Versus Forecast

The Short-Term Primary Load Forecast (891211) was prepared using regional estimates commencing January 1989. Since no 1989 actual data are used in this key component of the forecast process, it is worthwhile monitoring current year actuals to see how well the forecast is tracking. This section compares the forecast of system demand and customer loads with the actuals for 1989.

Table 6.1: Actual Total System Primary Demand Versus Forecast

	1-Hour Peak - GW					Energy - TW.h				
	Actual		% Yr/Yr	1989 Forecast	%	Actual		% Yr/Yr	1989 Forecast	%
	1988	1989	Growth	891211	Dev.*	1988	1989	Growth	891211	Dev.*
Jan	22.3	22.8	2.2	23.4	-2.3	12.9	13.1	1.7	13.5	-2.6
Feb	21.6	22.6	4.8	22.4	1.0	12.3	12.3	0.1	12.1	1.8
Mar	20.3	21.9	7.8	21.7	0.7	12.2	12.7	4.7	12.5	1.7
Apr	17.9	19.2	6.9	19.4	-1.5	10.4	11.1	6.4	10.8	2.4
May	17.8	18.0	1.1	18.5	-2.6	10.0	10.5	5.0	10.6	-0.8
Jun	18.8	20.0	6.3	19.1	4.9	10.1	10.6	4.4	10.5	0.3
Jul	19.2	20.0	4.1	19.5	2.6	10.6	11.2	5.0	11.0	1.1
Aug	19.5	19.4	-0.3	19.8	-2.1	11.0	11.0	0.2	11.1	-1.1
Sept	16.9	19.0	12.7	18.1	4.9	9.8	10.6	8.0	10.3	2.1
Oct	18.4	18.9	2.8	19.4	-2.8	10.9	11.2	2.8	11.3	-1.4
Nov	19.9	22.3	11.8	21.6	3.3	11.4	12.2	7.1	12.0	1.7
Dec	22.9	24.4	6.3	23.7	3.0	12.8	14.3	11.7	13.2	7.9
Avg	19.6	20.7	5.5**	20.6	0.8**	134.4+	140.8+	4.7**	139.2	1.1**

* Percent deviation from forecast.
** Based on annual average
\+ Total

The extraordinary continuous cold of December 1989, considered to be the most severe in over 100 years, sent the monthly energy consumption well over the forecast. After weather correction, the amount was 1.7% over the forecast.

Peak demands in June, July and September were also well in excess of forecast, however this result vanishes when the adjustment for abnormal weather is carried out.

6.2 Weather-Corrected Primary Demand Versus Forecast

As Load Forecast 891211 assumed normal weather in the peak and energy values, weather-corrected load data for 1989 provides a better standard for measurement of forecast performance than does the actual raw data. Table 6.2 demonstrates that the adjustment for abnormal weather makes a big difference in the view of forecast performance. The deviation from the peak forecast is seen to be negative, and the energy deviation falls to 0.4 percent from 1.1 percent.

Table 6.2: Weather-Corrected Total System Primary Demand Versus Forecast

	1-Hour Peak - GW					Energy - TW.h				
	Weather Corrected Demand		% Yr/Yr	1989 Forecast	%	Weather Corrected Demand		% Yr/Yr	1989 Forecast	%
	1988	1989	Growth	891211	Dev.*	1988	1989	Growth	891211	Dev.*
Jan	22.5	23.4	3.7	23.4	0.0	13.1	13.7	4.2	13.5	1.4
Feb	22.2	23.1	4.1	22.4	3.3	12.2	12.3	0.5	12.1	1.8
Mar	20.4	21.2	3.8	21.7	-2.5	12.2	12.6	2.8	12.5	0.4
Apr	18.6	19.6	5.6	19.4	0.8	10.4	11.0	5.7	10.8	1.5
May	17.3	18.0	3.8	18.5	-2.9	10.2	10.5	3.0	10.6	-1.4
Jun	17.9	18.8	5.0	19.1	-1.7	10.0	10.5	4.9	10.5	-0.1
Jul	17.9	19.3	7.3	19.5	-1.3	10.3	11.0	6.5	11.0	-0.6
Aug	18.3	18.8	2.5	19.8	-5.3	10.7	11.0	2.5	11.1	-1.4
Sept	17.4	18.2	5.1	18.1	0.6	9.9	10.5	5.6	10.3	1.4
Oct	18.6	19.2	3.3	19.4	-1.4	10.6	11.3	6.6	11.3	-0.5
Nov	21.0	21.9	4.4	21.6	1.8	11.5	12.0	4.6	12.0	0.2
Dec	22.3	23.4	4.8	23.7	-1.3	12.9	13.4	4.4	13.2	1.7
Avg	19.5	20.4	4.4**	20.6	-0.8**	134.1+	139.8+	4.2**	139.2+	0.4**

* Per cent deviation from forecast.
** Based on annual average
\+ Total

6.3 Diversity and Losses

System customers are billed on their maximum monthly peak load, whenever in the month it may occur (the non-coincident peak load). This quantity will be equal to or greater than that customer's load at the time of system peak (the coincident load). Diversity is defined as the coincident load minus the non-coincident peak load. It is, therefore, zero or negative because diversity reduces system peak demand. Diversity for individual system customers can only be measured at the time of system peak.

System peak losses are the difference between system peak and the sum of customers coincident loads, and system energy losses are the difference between energy sent out by the system and that received by the customers. It is not possible to allocate losses to individual customers. Losses are positive because they increase system demand.

For peak demands, the term net diversity and loss refers to the sum of the two.

Relationship Between System Demands and Customers Loads - 1989

The performance of Forecast 881212 on an average monthly basis was as follows:

Table 6.3: Performance of Forecast 881212

	Actual		Increase		1989 Forecast	Deviation from Forecast	
	1988	1989	MW	%	891211	MW	%
1-Hour Peak Average Peak MW							
System Demand	19632	20634	1002	5.1	20551	83	.4
Customer Loads	20111	21170*	1059	5.3	20963	207	1.0
Net Diversity and Losses	-479	-536	-57	10.6	-412	-124	30.1
% Customer Loads	-2.4	-2.5			-2.0		
Energy TW.h							
System Demand	134.4	140.8	6.4	4.8	139.2	1.6	1.2
Customer Loads	128.6	134.6	6.0	4.7	133.1	1.5	1.1
Losses	5.8	6.2	.4	6.7	6.1	.1	2.3
% Customer Loads	4.5	4.6			4.6		.1

* On-Peak peak, not Maximum Peak

Line losses in percent of customer energy and peak were very close to the 1989 Forecast at 4.6 percent actual versus 4.6 percent forecast. Losses and Diversity together (as a percent of customer peak) were -2.4 percent versus -2.0 percent forecast.

6.4 Unallocated Load

Since the forecast is the sum of the Regional estimates and the unallocated load that is eventually decided upon, the "actual" unallocated load is that which would have reduced the forecast error to zero.

Table 6.4: Average Monthly Results for 1988

Unallocated Load	Peak MW	Energy Av. MW
Forecast	-36	-30
"Actual"	171	146
Error (Actual-Forecast)	207	176

6.5 Detail of Customer Loads

(1) By Class

The monthly average results in terms of growth from 1988 and deviation from forecast are shown below:

Table 6.5.1: Sum of Customers' Loads (By Class) - 1989

1988 Average		Increase Over 1988 MW	Increase Over 1988 %	Deviation From F/C No. 891211 MW	Deviation From F/C No. 891211 %	Unallocated Load Forecast MW
Total	- Peak	1060	5.3	207	1.0	-36.0
	- Energy	731	5.0	175	1.2	-30.0
Municipal	- Peak	735	5.3	136	.9	-18.0
	- Energy	499	5.0	158	1.5	-19.2
Retail	- Peak	316	10.0	117	3.5	+10.0
	- Energy	172	8.2	71	3.2	+6.7
Direct	- Peak	7	.2	-47	-1.5	-28.0
	- Energy	59	2.4	-55	-2.1	-17.6

(2) By Region

Table 6.5.2 Sum of Customers' Loads (By Regions) - 1989

1989 Average		Increase Over 1988 MW	Increase Over 1988 %	Deviation From F/C No. 891211 MW	Deviation From F/C No. 891211 %	Unallocated Load Forecast MW
Total	- Peak	1060	5.3	207	1.0	-36.0
	- Energy	731	5.0	175	1.2	-30.0
Central	- Peak	533	5.6	71	.7	-13.0
	- Energy	370	5.3	90	1.2	-14.0
Western	- Peak	111	2.7	29	.7	-16.0
	- Energy	87	2.9	5	.2	-9.0
Eastern	- Peak	178	6.7	60	2.2	-7.0
	- Energy	111	5.9	48	2.5	-5.0
Geo. Bay	- Peak	149	12.5	48	3.7	-7.0
	- Energy	95	11.7	36	4.1	+5.0
N. Eastern	- Peak	45	2.7	-3	-.2	-6.0
	- Energy	45	3.6	1	.1	-5.0
N. Western	- Peak	45	4.7	2	.2	-1.0
	- Energy	22	2.9	-7	-.9	-1.0

Reasons for varying growth rates over 1988 and deviations from forecast are diverse, but may generally be related to economic activity and the exceptionally cold weather of December 1989.

TABLE A

FORECAST ERROR (%)*
EAST SYSTEM DECEMBER PEAK

Year Forecast Made	Years After Forecast									
	1	2	3	4	5	6	7	8	9	10
1950	-5.6	-11.1	-14.7	-16.6	-18.1	-25.4				
1951	1.1	0.1	-0.4	-1.5	-9.3					
1952	2.2	5.0	6.1	-2.0	-4.1					
1953	2.3	4.0	-2.5	-3.9	-4.1	-6.6				
1954	-0.4	-5.2	-6.0	-5.2	-7.4					
1955	-3.0	-2.5	-1.5	-3.2	-6.7	-5.3				
1956	1.6	5.7	4.8	2.0	3.7	5.2				
1957	2.8	1.5	-0.9	3.4	6.3	6.6	6.2	6.7		
1958	-0.9	-2.2	2.1	4.1	3.8	1.4	1.4	-1.8	-4.7	-3.4
1959	0.1	2.8	6.1	6.4	4.1	4.5	0.6	-2.9	-2.0	-7.4
1960	2.6	5.3	6.0	3.2	3.6	0.4	-2.9	-1.6	-6.6	-6.2
1961	1.9	3.2	0.8	0.6	-3.0	-5.4	-3.7	-8.3	-7.8	-8.5
1962	1.0	-1.9	-1.6	-4.8	-7.5	-6.6	-10.6	-10.1	-10.7	-7.1
1963	-2.7	-2.3	-6.0	-8.6	-7.1	-11.6	-10.8	-11.3	-7.5	-10.7
1964	-1.6	-4.4	-6.5	-5.3	-9.4	-8.7	-9.4	-6.4	-4.4	-5.1
1965	-1.2	-3.7	-1.5	-5.9	-5.2	-5.8	-1.7	-5.1	-5.6	0.0
1966	-1.0	0.2	-5.9	-4.2	-4.8	-0.6	-4.0	-4.4	1.7	0.1
1967	1.2	-3.1	-2.0	-2.2	2.4	-0.8	-1.0	5.5	4.2	3.3
1968	-0.3	1.7	1.7	7.0	3.2	2.7	9.5	8.2	7.3	16.5
1969	0.9	1.9	7.0	5.2	5.6	13.0	11.3	10.3	19.8	27.4
1970	1.0	6.7	5.7	5.5	12.0	10.9	9.8	19.2	26.8	30.5
1971	6.2	3.4	3.6	10.1	9.0	8.0	17.3	24.8	28.4	33.1
1972	1.9	2.0	8.6	7.2	6.0	15.0	22.3	25.9	30.4	41.5
1973	0.4	7.9	7.5	6.5	15.6	22.9	26.5	31.1	42.2	50.0
1974	6.3	6.3	7.0	17.4	26.0	29.7	34.4	45.8	53.9	47.5
1975	1.1	1.8	12.2	21.0	24.3	28.4	39.2	46.7	40.5	56.3
1976	-1.9	8.0	15.9	19.0	23.0	33.0	40.0	34.0	48.9	40.2
1977	5.8	13.0	15.6	19.6	29.4	35.9	29.4	43.2	34.3	41.9
1978	4.7	6.0	8.4	16.0	20.7	14.1	25.2	16.5	21.9	29.3
1979	1.4	1.2	6.7	10.7	4.4	14.4	5.9	10.3	16.4	8.6
1980	1.2	6.8	10.7	4.0	12.2	2.5	5.3	9.8	1.2	-0.6
1981	3.4	5.1	-2.5	5.0	-3.9	-1.2	3.0	-5.0	-6.6	
1982	4.8	-2.9	4.8	-4.4	-1.8	2.2	-6.1	-8.0		
1983	-6.3	1.5	-7.5	-5.2	-2.0	-10.5	-13.2			
1984	4.8	-4.5	-3.0	0.4	-8.2	-10.6				
1985	-5.2	-3.8	-0.6	-9.2	-11.9					
1986	0.8	4.5	-4.1	-7.1						
1987	4.7	-3.6	-6.2							
1988	-1.5	-4.3								
1989	-2.0									

* Difference between forecast made 1 to 10 years prior to year indicated divided by actual. A negative sign indicates forecast is too low. Forecasts of peak are weather-normal while actual peak includes the impact of weather. The "forecast errors" above thus contain two elements - pure forecast error and weather effects.

7.0 UNCERTAINTY IN THE LOAD FORECAST

7.1 Introduction

The methodology used to estimate the uncertainty band around the 1989 Load Forecast is almost identical to that introduced last year and reported in LF881212. The uncertainty in the load forecast is decomposed into the uncertainty associated with economic growth in Ontario and that associated with future trends in the pattern of electricity consumption. This is done via a stochastic simulation procedure which generates the probability distributions of these two dimensions of uncertainty using two empirically constructed Variable Elasticity Models - for load growth and economic growth.

7.2 The Estimated Equations

The economic growth model and the energy model were updated with 1988 data and re-estimated. The estimated equations are as follows:

i) Economic Growth Model

$$\log(GDP_t) = \underset{(23.5)}{0.592} * \log(POP_t) + \underset{(27.8)}{0.0087} * [\log(POP_t)]^3 + e_t$$

Estimation Period: 1962 - 1988
Adjusted R-Squared: 0.991

ii) Energy Model

$$\log(ENERGY_t) = \underset{(10.9)}{-32.6} + \underset{(11.1)}{5.98} * \log(GDP_t) - \underset{(8.6)}{0.21} * [\log(GDP_t)]^2 + e_t$$

Estimation Period: 1947 - 1988
Adjusted R-Squared: 0.998
Standard Error of Equation at Mean = 198 average megawatts

7.3 Estimated 80% Confidence Interval for Annual System Energy

The probability distribution for the 1989 Load Forecast was again produced using the stochastic simulation approach.

This procedure was carried out as follows. First, standard Monte Carlo simulation methods were used to draw 500 samples from the assumed distribution of Ontario population for every year of the forecast period. Then, using this data, the economic growth model was simulated yielding 500 samples of GDP for each forecast year. Finally, the energy model was simulated giving 500 samples of Ontario Hydro energy for each year. These simulated samples were then used to produce distributions for population, GDP and load.

The 80% confidence interval for system energy is reproduced in section 2 on Table 2.2. The results have been adjusted, from those produced by the actual simulation, so that the median corresponds to the official forecast. The required adjustments are shown in the table below.

Required Adjustment

Year	TW.h	Percent
Short-Term		
1989	1.90	1.36
1990	-0.81	-0.57
1991	-0.58	-0.39
1992	-1.02	-0.66
1993	-1.25	-0.79
1994	-1.78	-1.09
Long-Term		
1995	-0.42	-0.25
2000	-4.37	-2.30
2005	-5.19	-2.47
2010	-6.39	-2.77
2015	-12.57	-4.94

7.4 Refinements to the 1988 Methodology included in the 1989 Load Forecast

Several refinements to the 1988 procedure were incorporated, reflecting lessons learned after using the methodology for the first time.

The major differences between the procedure used to derive the 1988 and the 1989 probability distributions for the load forecast are summarized below. Further information about the development of Hydro's uncertainty measures is contained in "Uncertainty in the Load Forecast - A Summary of Results Developed in 1988 and 1989".

Population Standard Deviation

In the 1988 calculation of the standard deviation of the population growth rates, the average of all the forecasts for any particular time interval within the forecast horizon was calculated to derive the mean value used to scale the historical standard deviations. In the 1989 calculation, only the forecast growth rate over the time interval starting in the base year of the forecast period was used. For example, rather than calculating the average growth for all the 10-period ahead forecasts between 1987 and 2010, only the average growth from 1987 to 1997 was used to scale the 10-year ahead standard deviation. This tends to widen the GDP distribution in the early years of the forecast period and narrow it slightly at the end.

The adjustment in procedure was necessary because the significant change in the forecast population growth rate over the next twenty-five years makes the 1988 approach extremely sensitive to the length of the forecast horizon selected.

Simulation Procedure

During 1989 two approaches to estimating the uncertainty around the load forecast were investigated. Both were based on single-equation econometric models for load but they differed in terms of both specification and the statistical assumptions required to derive the total probability distribution for load. These methods are referred to as Monte Carlo Simulation and Stochastic Simulation.

The Monte Carlo Simulation approach is characterized by the use of simulation techniques applied to explicitly postulated statistical distributions for the coefficients, residual error and explanatory variables so as to generate the appropriate joint distribution of all these effects. Monte Carlo simulation requires specification of a distribution characterized by parameters such as the mean and variance. Typically a normal distribution is assumed. Random numbers are generated according to the prescribed distributions to permit the simulation of joint effects. The methodology used takes into account the covariance between explanatory variables.

Stochastic simulation is viewed here as a more general form of simulation than Monte Carlo simulation in that samples may be drawn from an actual or generated distribution of data in addition to a statistically defined or parametric distribution. In this context, it is the use of the estimated distribution for Ontario GDP - in its raw form - which constitutes the major distinction between this simulation approach and the Monte Carlo method. It was this methodology which was used in both 1988 and 1989 with, however, one important difference.

In the 1988 Load Forecast the probability distribution for load was inferred directly from the distribution for GDP via the Energy Model. This approach produces essentially a range forecast; the expected values for load directly result from the distribution of GDP and the estimated parameters of the equation. This was necessary because the software capability required to produce a total stochastic simulation was not available at the time. Once the software was operational, a priority for 1989 was the simulation of the coefficient and the residual error distributions along with the GDP distribution, i.e. a total stochastic simulation. The treatment of all sources of uncertainty by the Monte Carlo methods was considered superior in principle to the range forecast approach.

The total stochastic simulation results for 1989 indicated a slightly wider band in the long run than either the Monte Carlo or the forecast range alternative. However, closer examination of the distribution for the first few years of the forecast indicated an unacceptably wide bandwidth. This is because the coefficient and residual error uncertainty do not change in absolute terms over time. The residual error was sufficiently large in the variable elasticity model that the bandwidth for the first year of the forecast blew up to ±9% of the forecast growth rate. This is one of the short-run consequences of using a long run-model. The Monte Carlo distribution is based on a short-term model specification and has a much smaller fitting error. Its one-year ahead bandwidth also appeared wide, but was much less extreme than the other technique. Unfortunately, the change in the GDP distribution, and perhaps other factors, impacts the Monte Carlo procedure such that the long-term bands, including residual error and coefficients, were narrower than the 1988 bandwidth. As the intent in seeking a total simulation method was to widen the long-term band, the Monte Carlo distribution was not acceptable.

The selected approach for 1989 was to splice the two stochastic simulation variants together in the year 2000. For the period 1988 - 2000, the 1989 version of the range forecast results was adopted. Beyond 2000, to reflect the increased uncertainty in the relationship of GDP to load that is reflected in the distributions of the coefficients and the residual errors, the growth rates for the total stochastic simulation were applied across the entire year 2000 distribution of the range forecast.

Scaling Procedure

The original 1988 stochastic simulation distribution was scaled to the official 1988 forecast by subtracting the difference between the median of the generated

distribution and the official median forecast in each year from all values of the distribution in that year. Applying the same absolute amount across the full range, from low to high load values, introduced a downward bias to the resulting distribution which was not intended. All the input variables had slightly greater risk on the high side yet close examination of the 1988 distribution indicates that the 1988 load distribution was, if anything, biased on the low side. This was readily corrected by adjusting the entire distribution by the percent difference at the median rather than the absolute difference. This correction explains why the 1989 distribution tends to have higher values for the 1988-2000 period than the 1988 distribution. The effect persists beyond 2000, but is masked by the large impacts of the change in simulation procedure.

8.0 GLOSSARY

8.1 Demand (Versus Load)

Demand means the electrical output from the Corporation's generating resources together with outside purchases required to supply the load of the Corporation's customers. In this report demand refers to the level of demand at the generating stations, while load refers to the flow of electricity at the wholesale billing points. Each term refers to peak or energy as specified in context.

Power means an instantaneous time rate of delivery of energy. Peak refers to the power averaged over a short period during which time the load is at its maximum. Energy demand is the accumulation of power over time, which results in an amount of useful work (or heat, lighting etc.)

In this report energy is reported in units of terawatt-hours or else in average megawatts. To obtain average megawatts for a period of time, the megawatt-hour figure is divided by the number of hours in the period.

Annual and Winter Peak Demand

All peak demands shown in this report incorporate the effects of typical weather conditions associated with the monthly peak demands. Under these conditions the annual peak demand occurs in December and the winter peak normally occurs in January.

Primary Peak Demand

Primary Peak Demand is the total generated and purchased minus secondary sales.

Secondary Sales:

Secondary Sales are of two types:: Ontario At-Will and Export.

Ontario At-Will:

These sales are at-will energy displacement sales from available resources in Ontario which are interruptible to supply the Primary contractual committments. These displace alternative energy sources on a fully interruptible, and at-will basis.

Export:

Electricity sales outside Ontario from available resources which are interruptible to supply the Primary Contract committments. Firm Export Sales are 'firm' relative to other Secondary Sales, but are Interruptible as necessary to meet the Primary Contract commitment.

Primary Demand in Terms of Generation

Primary Peak Demand is the sum of the customers' peak requirements (not necessarily coincident with the system peak) adjusted by an allowance for diversity and losses. This figure gives the primary peak demand at the level of the generating stations.

- **Peak** - The figures shown are those for the time of the maximum 1-hour or 20-minute peak demand.

An allowance for the weather effect expected on the typical monthly peak day is incorporated into the Primary Peak Demand for each month. Diversity and losses are affected by extreme weather as well.

- **Energy** - Monthly energy demands shown in this report are expressed in terawatt hours and average megawatts, in order to give an immediate impression of load factor, and also to make successive monthly values independent of differences arising solely from the varying lengths of the months.

Ontario Primary Demands in Terms of Generation

East System

Includes:

The primary power and energy loads of Municipalities, Industrial Customers, and Retail Customers in Ontario within the geographic boundaries of the Central, Western, Eastern, Georgian Bay and Northeastern Regions, together with appropriate diversity and losses.

Power and energy delivered free of charge by Ontario Hydro to Spruce Falls Power and Paper Company Limited in compensation for the effects of Little Long Generating Station on the Company's Smoky Falls Generating Station.

Excludes:

Power and energy exported to the United States and the Province of Quebec. Also excluded are deliveries under exchange agreements, namely, to Fort Erie on behalf of the CNP Company, and to Cornwall on behalf of the St. Lawrence Power Company. In both of these cases the amount of power delivered is made up at another point on the system so that there is no resultant demand on the Corporation's resources.

The loads of retail customers in Hornepayne, although customers of the Northeastern Region, because they are supplied from power resources within the Northwestern Region.

West System

Includes:

The primary power and energy loads of Municipalities, Direct and Retail Customers in Ontario within the geographic boundaries of the Northwestern Region, and the loads of retail customers in Hornepayne together with appropriate diversity and losses. The latter customers are included because they are supplied from resources within the Northwestern Region.

Power and energy delivered free of charge to Boise Cascade Company (Kenora), as compensation for the effects of Whitedog Falls Generating Station on the output of its generating stations.

Excludes:

Power and energy exported by Ontario Hydro to the United States and the Province of Manitoba.

Power and energy delivered to Boise Cascade at Fort Frances in exchange for the output of the Company's Calm Lake and Sturgeon Falls Generating Stations.

Ontario primary demands (both East and West Systems) exclude the delivery of turbo replacement power to various paper companies.

8.1.1 Basic Load Forecast

The Basic Load Forecast shows what would happen to electricity demand if Ontario Hydro did not adopt new activities to affect electricity demand. However, the current Demand/Supply Plan Study indicates that some future electricity needs of the province will be met by other means than by increasing supply. Ontario Hydro has programs to promote changes in the pattern of usage to allow some of the province's future electricity needs to be met by demand reductions.

8.1.2 Primary Load Forecast

The Primary Load Forecast takes into account the effect on Ontario Hydro demand of future Ontario Hydro activities designed to affect the level and shape of the load. It is derived by subtracting from the Basic Load Forecast the net effect of Load Displacement generation and Ontario Hydro's incentive-driven demand management programs which include:

(1) changes in rate structure such as time-of-use, off-peak incentives, etc;

(2) financial incentives such as grants or loans, etc.

It is the Primary Load Forecast which is to be used for supply planning purposes.

8.2 Diversity and Losses

Diversity is the difference between the sum of (individually metered) customer loads at the time of system peak and the arithmetic sum of the peak loads of all the customers regardless of whether they coincide with the system peak or not. Since individual customers experience their peak loads at diverse times, the arithmetic sum of their peak loads will be greater than the sum of customer loads at the time of system peak, and therefore the value for diversity is always negative.

Losses are the sum of electrical losses and consumption incurred in transmitting the electricity from the generating stations' terminals to all the customer metering points. This is evaluated by taking the difference between customer loads and system demands measured at the generating stations.

The figure for diversity and losses together will be positive if losses exceed diversity, and negative when diversity exceeds losses.

Diversity is a function of the timing of end-use utilization which is affected by social patterns and weather conditions. Losses are due mainly to transmission line loadings determined by system configuration and operation. System operation depends on hydraulic generation resources, export and circulating power flow, outages, etc.

There is no diversity in energy demand. The difference between the primary energy and the energy delivered to customers is losses.

8.3 Customers' Loads

Customers' Loads are the maximum peak loads of system customers which include cost contract municipalities, industrial customers and retail customers. Estimates of these loads are provided by the Regional Marketing Managers. The totals of these non-coincident customers' loads are referred to as the sums of